Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Tue, Jul 1, 2025 at 1:28 PM
To: DJ Wheeler <dwheeler@trinityconsultants.com>
Cc: "Thornberry, Jill" <Jill.Thornberry@williams.com>, "Hortert, Chris" <Chris.Hortert@williams.com>, "Louwers, Amy" <amy.louwers@williams.com>

Hi DJ,

Thanks for the explanation. I've added 60.112c(e)(2)(i) and (ii) to Condition 9.1.8. of the operating permit. Because 60.112c(e)(2)(i) requires the provisions of 60.112c(d)(5) to be met and 60.112c(d)(5)(ii) requires the visible emissions monitoring in 60.113c(c)(1)(iv)(A) to be met, the provisions of 60.112c(d)(5) and 60.113c(c)(1)(iv)(A) will also be applicable and, therefore, were added to the storage vessel degassing requirements as well.

You should receive a message with the dates of the public and EPA comment periods within the next few days.

Thanks,
- Sarah

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

DJ Wheeler <dwheeler@trinityconsultants.com> Mon, Jun 30, 2025 at 4:41 PM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>
Cc: "Thornberry, Jill" <Jill.Thornberry@williams.com>, "Hortert, Chris" <Chris.Hortert@williams.com>, "Louwers, Amy" <amy.louwers@williams.com>

Hi Sarah,

Thank you for considering Williams's comments on the Title V permit for the Natrium Gas Plant. Paragraph 40 CFR 60.112c(e) refers specifically to non-routine and infrequent degassing emissions that occur during tank maintenance events (e.g., once every ten years per API recommendations). Because these degassing events happen infrequently, the normal means of controlling tank emissions may not be capable of capturing these additional degassing vapors. Therefore, many operators choose to use temporary or portable control devices (e.g., flares, combustors, carbon beds, cross-compression) to control degassing emissions as is allowed by 40 CFR 60.112c(e)(2)(i) and (ii). Williams respectfully requests the addition of paragraphs 40 CFR 60.112c(e)(2)(i) and (ii) to ensure that Williams can rely on the compliance options provided in NSPS Kc specifically for these non-routine and infrequent degassing events.

Williams agrees with all of the other updates to the Title V permit. Thanks again for your consideration, and let us know if you have any questions.

Thanks,

DJ Wheeler

Managing Consultant

P 614.568.8851 M 231.670.3072

Email: dwheeler@trinityconsultants.com

440 Polaris Pkwy, Suite 275 Westerville, OH 43082

Connect with us: LinkedIn / Facebook / Twitter / YouTube / trinityconsultants.com

Stay current on environmental issues. Subscribe today to receive Trinity's free *EHS Quarterly*.

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Mon, Jun 30, 2025 at 1:15 PM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>, "Thornberry, Jill" <Jill.Thornberry@williams.com>

Hi Chris,

I spoke with Amy as you recommended. The following were the responses which I discussed with her:

Section 3.7. Permit Shield

The permit shield cannot be used to cover the potential changes or amendments to a rule or regulation. The Title V permit must contain the requirements which are applicable to the facility at the time that the permit is written and issued. In order to ensure that the requirements applicable to the unconstructed equipment are accurate and up-to-date in the Title V permit, Condition 3.1.15. was added to require a modification application to be submitted for the purposes of updating the applicable requirements as necessary when the equipment is installed and begins operation. Additionally, under 45CSR30-6.6.a., a permit shall be reopened and revised if "additional applicable requirements under the Clean Air Act or the Secretary's rules become applicable to a major source with a remaining permit term of three or more years".

Section 9.0. 40 CFR 60, Subparts Kb and Kc Storage Tanks

Condition 9.1.8.b. - Please provide the reasoning for adding the provisions of 40 C.F.R. 60.112c(e)(2)(i) and (ii) to the Title V permit. These provisions for storage vessel degassing appear to be inapplicable to the current plan for the storage tanks at the facility. Based on the information provided in the application and in the answers which you submitted in the email dated May 30, 2025 as well as the current permit requirements, the closed vent systems for the tanks will either be routed to a process or a fuel gas system, and not to a flare or non-flare control device.

Condition 9.5.2. - The phrase "whichever is later" was removed from this condition.

Section 15.0. NPP: Turbines and Duct Burners

Condition 15.2.8.b. - Since an excursion prior to the performance test is defined as the inlet temperature outside of the manufacturer's recommended range and not the expected temperature range, the expected catalyst bed operating temperature range was removed from the permit and the fact sheet. In order to ensure that the operating temperature specification is readily available the following was added to this condition: "The permittee shall maintain a copy of the manufacturer's operation specifications for the oxidation catalyst in a form suitable and readily available for expeditious review. Maintenance of the specifications in an electronic format is acceptable."

Additionally, following the Title V Program Manager's review, several small corrections (typos, references, etc.) were made throughout the pre-draft permit and fact sheet. However, the following changes were also made to the permit:

In Condition 3.7.2.g. of the permit shield, the applicability of 40 C.F.R. Part 97 Subpart GGGGG to facilities located in West Virginia has been stayed under 40 CFR 52.38(b)(2)(iii)(D)(1). Therefore, the references to Subpart GGGGG were replaced with Subpart EEEEE per 40 CFR 52.38(b)(2)(ii)(D)(1).

Condition 3.1.15. was revised as follows: "Upon construction of the equipment in the Emission Units Table specified as “Not Yet Constructed”, the permittee shall meet all applicable requirements for the emission units. The permittee shall notify the Secretary, in writing ~~or electronically~~, of the actual date of the initial startup of these emission units no later than thirty **(30)** calendar days after such date. Within 180 days of equipment startup, the permittee shall submit, as necessary, a complete application for a significant Title V permit modification pursuant to 45CSR30 to incorporate any amendments or revisions of the applicable requirements." Please note that the written notification may be submitted electronically.

Please let me know if you have any further comments or questions.

Thanks,
- Sarah
[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Fri, Jun 27, 2025 at 2:57 PM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>, DJ Wheeler <dwheeler@trinityconsultants.com>
Cc: "Thornberry, Jill" <Jill.Thornberry@williams.com>

Good Afternoon Sarah,

Please see the attached with our 4 comments. If you have any questions please reach out.

Have a good weekend,

Chris

Chris Hortert, P.G. | Williams | Environmental Specialist | Ohio River Supply Hub
Mobile: 412-452-1893 |



**Registered in Pennsylvania*

If you have received this message in error, please reply to advise the sender of the error and then immediately delete this message.

From: Barron, Sarah K <sarah.k.barron@wv.gov>
Sent: Thursday, June 19, 2025 8:08 AM
To: Hortert, Chris <Chris.Hortert@williams.com>; DJ Wheeler <dwheeler@trinityconsultants.com>
Subject: [EXTERNAL] Re: Title V Pre-Draft Permit; R30-05100142-2025

CAUTION! EXTERNAL SENDER STOP. ASSESS. VERIFY!! If suspicious, STOP and click the Phish Alert Button

Hi Chris,

[Quoted text hidden]
[Quoted text hidden]

DPPermit R30-05100142-2024 20250624 0902_DJW.pdf
1441K

West Virginia Department of Environmental Protection

Harold D. Ward
Cabinet Secretary

Permit to Operate

Pursuant to
Title V
of the Clean Air Act

Issued to:

Blue Racer Midstream, LLC
Natrium Extraction and Fractionation Processing Plant (NEFPP) and Natrium Power Plant (NPP)
R30-05100142-2025

Laura M. Crowder
Director, Division of Air Quality

Issued: [Date of issuance] • Effective: [Equals issue date plus two weeks]
Expiration: [5 years after issuance date] • Renewal Application Due: [6 months prior to expiration]

Permit Number: **R30-05100142-2025**
Permittee: **Blue Racer Midstream, LLC**
Facility Name: **Natrium Extraction and Fractionation Processing Plant (NEFPP) and Natrium Power Plant (NPP)**
Permittee Mailing Address: **14786 Energy Road, Proctor, WV 26055**

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45CSR30 - Requirements for Operating Permits. The permittee identified at the above-referenced facility is authorized to operate the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Facility Location:	Proctor, Marshall County, West Virginia
Facility Mailing Address:	14786 Energy Road, Proctor, WV 26055
Telephone Number:	(304) 455-4220
Type of Business Entity:	LLC
Facility Description:	Natural Gas Extraction/Fractionation Facility
SIC Codes:	Primary: 1321; Secondary: 4911
UTM Coordinates:	512.1 km Easting • 4,400.8 km Northing • Zone 17

Permit Writer: Sarah Barron

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§ 22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §22-5-14.

Issuance of this Title V Operating Permit does not supersede or invalidate any existing permits under 45CSR13, 14 or 19, although all applicable requirements from such permits governing the facility's operation and compliance have been incorporated into the Title V Operating Permit.

Table of Contents

1.0. Emission Units and Active R13, R14, and R19 Permits 3

2.0. General Conditions 9

3.0. Facility-Wide Requirements and Permit Shield 17

Source-specific Requirements

4.0. Hot Oil Heaters 26

5.0. Cryogenic HMO/Stabilizer Heaters 35

6.0. Regeneration Gas Heaters 40

7.0. Fire Pumps 42

8.0. Glycol Dehydration Units 48

9.0. 40 CFR 60, Subparts Kb and Kc Storage Tanks 51

10.0. Flare 65

11.0. Ethane Amine Units 71

12.0. Other Storage Tanks and Liquids Loading/Unloading 73

13.0. Pigging Operations 75

14.0. 40 CFR 60, Subparts OOOO, OOOOa, and OOOOb Requirements 78

15.0. NPP: Turbines and Duct Burners 135

16.0. NPP: Fuel Gas Heaters 156

17.0. NPP: Emergency Generator and Emergency Fire Pump Engine 158

18.0. NPP: Storage Tanks 166

19.0. NPP: Component Leaks 167

1.0 Emission Units and Active R13, R14, and R19 Permits

1.1. Emission Units

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Heaters					
S001	P001	Hot Oil Heater	2014	216.7 MMBtu/hr	None
S012	P012	Regeneration Gas Heater	2013	9.7 MMBtu/hr	None
S013	P013	Cryogenic Hot Medium Oil (HMO) Heater	2013	26.3 MMBtu/hr	None
S016	P016	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S017	P017	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S018	P018	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S019	P019	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S024	P024	Regeneration Gas Heater	2018	9.7 MMBtu/hr	None
S026	P026	Cryogenic HMO Heater	2018	26.3 MMBtu/hr	None
S036	P036	Regeneration Gas Heater	2019	9.7 MMBtu/hr	None
S037	P037	Cryogenic HMO Heater	2019	26.3 MMBtu/hr	None
S040	P040	Regeneration Gas Heater	Not Yet Constructed	19.28 MMBtu/hr	None
S041	P041	Cryogenic HMO Heater	Not Yet Constructed	54.67 MMBtu/hr	None
S044	P044	Regeneration Gas Heater	Not Yet Constructed	9.7 MMBtu/hr	None
S045	P045	Cryogenic HMO Heater	Not Yet Constructed	26.3 MMBtu/hr	None
S048	P048	Regeneration Gas Heater	Not Yet Constructed	9.7 MMBtu/hr	None
S049	P049	Cryogenic HMO Heater	Not Yet Constructed	26.3 MMBtu/hr	None
S052	P052	Hot Oil Heater	Not Yet Constructed	61.58 MMBtu/hr	None
S053	P053	Hot Oil Heater	Not Yet Constructed	61.58 MMBtu/hr	None
S056	P056	Stabilizer Heater	Not Yet Constructed	10.09 MMBtu/hr	None

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Glycol Dehydration Units					
S006	P001[1]	Glycol Dehydration System Glycol Dehydration Flash Tank	2011	460 mmscf/day	C001[1]
Storage Tanks[2]					
TK-802	P001	Natural Gasoline Storage Tank	2011	714,000 gal	VRU and Natural Gas Blanket[3]
TK-2802	P001	Natural Gasoline Storage Tank	2014	1,260,000 gal	VRU and Natural Gas Blanket[3]
TK-3802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	714,000 gal	VRU and Natural Gas Blanket[3]
TK-4802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	1,260,000 gal	VRU and Natural Gas Blanket[3]
TK-5802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	714,000 gal	VRU and Natural Gas Blanket[3]
TK-6802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	1,260,000 gal	VRU and Natural Gas Blanket[3]
TK-7802	TK-7802	Refrigerated Propane Storage Tank	Not Yet Constructed	4,200,000 gal	VRU
US-800	Flare[4]	Spherical NGL Storage Tank	2011	2,142,000 gal	Pressure Tank
US-801	Flare[4]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank
US-804	Flare[4]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank
US-805	Flare[4]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank
US-2800	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	2,142,000 gal	Pressure Tank
US-2801	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	865,200 gal	Pressure Tank

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
US-2804	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	865,200 gal	Pressure Tank
US-2805	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	865,200 gal	Pressure Tank
N/A	N/A	Four (4) Pressurized NGL Bullet Tanks (V-1905, V-1915, V-1925, V-1935)	2014	90,000 gal (each)	Pressure Tank
N/A	N/A	Four (4) Pressurized NGL Bullet Tanks (V-2905, V-2915, V-2925, V-2935)	Not Yet Constructed	90,000 gal (each)	Pressure Tank
TK-906	TK-906	Slop Tank	2011	21,000 gal	None
TK-2906	TK-2906	Slop Tank	Not Yet Constructed	21,000 gal	None
TK-907	TK-907	Produced Water Tank	2012	63,000 gal	None
TK-2907	TK-2907	Produced Water Tank	Not Yet Constructed	63,000 gal	None
Other Emission Units					
S011	P005	Ethane Amine Regenerator	2012	129 mmscf/day	None
S054	P054	Ethane Amine Regenerator	Not Yet Constructed	129 mmscf/day	VRU
S008	P008	Product Loading (Truck, Rail, Propane Barge)	2011	3,600 gpm (truck) 4,000 gpm (rail) 4,000 gpm (barge)	VRU
S015	S015	Slop Water Truck Loading	2011	150 gpm	None
S033	P033	Natural Gasoline Loading (Barge)	2017	4,000 gpm	None
S055	P055	Pressurized NGL/Condensate Unloading	2012	3,600 gpm	None
L-1	L-1	Gasoline Dispenser Loading	2017	20 gal/hr	None
S002	P002	Caterpillar Model C18 Fire Pump #1 Diesel (Manufactured 2011)	2012	700 HP	None
S003	P003	Caterpillar Model C18 Fire Pump #2 Diesel (Manufactured 2011)	2012	700 HP	None
S058	P058	Diesel-Fired Fire Pump Engines/Generators[6]	2020	3,000 HP (total)	None
S035	P035	Pigging Operations	2017	N/A	VRU/ None[5]

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Fugitive Emissions Sources					
FUG AREA 1	N/A	Fugitive Area 1	2011	N/A	None
FUG AREA 2	N/A	Fugitive Area 2	2011	N/A	None
FUG AREA 3	N/A	Fugitive Area 3	2018	N/A	None
FUG AREA 4	N/A	Fugitive Area 4	2019	N/A	None
FUG AREA 5	N/A	Fugitive Area 5	Not Yet Constructed	N/A	None
FUG AREA 6	N/A	Fugitive Area 6	Not Yet Constructed	N/A	None
FUG AREA 7	N/A	Fugitive Area 7	Not Yet Constructed	N/A	None
S010	N/A	Unpaved Roads	2011	N/A	None
Control Devices					
S004A	P004A	Callidus CAL-MP Staged, Multi-Point Ground Flare System (C004A)	2015	19,800,000 scf/hr	N/A
S034	P034	Propane Pig Trap Flare (C034)	2017	72,000 scf/hr	N/A

Control Device ID	Emission Unit	Pollutant	Control Device	Control Efficiency
C004A	Maintenance, Blowdowns, Pressure Relief Valves	VOCs	Flare (S004A)	98.0 %
		Total HAPs		98.0 %
C034	Pigging Flare (S034)	VOCs	Pigging Flare (S034)	98.0%

(1) Still vent and flash tank vapors from S006 will be routed to the Hot Oil Heater (S001: C001) and used as fuel.

(2) Other storage tanks that are not listed here (see Table N-3 in permit application R13-2896F) but meet the *de minimis* requirements under 45CSR13 (*Storage vessels having less than 10,567 gallons capacity containing petroleum or organic liquids with a vapor pressure of 1.5 psia or less at storage temperature, provided that the emissions from all such organic liquid storage tanks, in the aggregate, are less than 2 tons per year for hazardous air pollutants or VOCs*) are authorized at the facility.

(3) Tank uses a natural gas blanket to prevent emissions of natural gasoline. Working/breathing losses of natural gas blanket are collected by a VRU and sent to Hot Oil Heater (S001) as a supplemental fuel.

(4) This tank shall be pressurized in excess of 204.9 kPa (which exempts the tank from applicability to 40 CFR 60, Subpart Kb) and normally has no emissions. In the case of emergency, emissions from the tank can be flared in C004A.

(5) The pigging vapors from the three truck side 30" Inlet receivers are captured by the VRU and routed back to the process.

(6) Under R13-2896I, the construction of one or more diesel-fired fire pump engines with a maximum total rating of 3,000 HP was permitted as emission unit S058. As of the writing of this operating permit, two 800-HP fire pump engines have been installed at the facility under the emission unit ID S058.

Note: Other storage tanks and pressure vessels not listed within the Title V Equipment Table are authorized at this facility according to insignificant activities listed under the Title V General Form Section 24, Item 19.

Natrium Power Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device[1]
Combustion Turbines[2]					
Scenario A					
TB1A	TB1AE	GE LM6000PG SPRINT Combustion Turbine #1	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC1, SCR1
TB2A	TB2AE	GE LM6000PG SPRINT Combustion Turbine #2	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC2, SCR2
TB3A	TB3AE	GE LM6000PG SPRINT Combustion Turbine #3	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC3, SCR3
TB4A	TB4AE	GE LM6000PG SPRINT Combustion Turbine #4	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC4, SCR4
Scenario B					
TB1B	TB1BE	Siemens SGT-800 Combustion Turbine #1	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC1, SCR1
TB2B	TB2BE	Siemens SGT-800 Combustion Turbine #2	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC2, SCR2
TB3B	TB3BE	Siemens SGT-800 Combustion Turbine #3	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC3, SCR3
TB4B	TB4BE	Siemens SGT-800 Combustion Turbine #4	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC4, SCR4
Other Combustion Devices					
TB1A/B	TB1A/BE	Duct Burner #1	Not Yet Constructed	475.1 MMBtu/hr	OC1, SCR1
TB2A/B	TB2A/BE	Duct Burner #2	Not Yet Constructed	475.1 MMBtu/hr	OC2, SCR2
TB3A/B	TB3A/BE	Duct Burner #3	Not Yet Constructed	475.1 MMBtu/hr	OC3, SCR3
TB4A/B	TB4A/BE	Duct Burner #4	Not Yet Constructed	475.1 MMBtu/hr	OC4, SCR4
FH1	FH1E	Fuel Gas Heater #1	Not Yet Constructed	9.9 MMBtu/hr	None
FH2	FH2E	Fuel Gas Heater #2	Not Yet Constructed	9.9 MMBtu/hr	None
EG1	EG1E	Emergency Generator	Not Yet Constructed	1,676 HP	None

Natrium Power Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device[1]
FP1	FP1E	Emergency Fire Pump Engine	Not Yet Constructed	700 HP	None
Storage Tanks					
OT1 to OT4	OT1E to OT4E	Lubricating Oil Tank #1-4[3]	Not Yet Constructed	5,000 gal	None
OT5 to OT8	OT5E to OT8E	Waste Oil Tank #1-4[3]	Not Yet Constructed	250 gal	None
AT1	AT1E	Ammonia/Urea Storage Tank[4]	Not Yet Constructed	60,000 gal	None
WS1 to WS4	WS1E to WS4E	Washout Sumps #1-4[3]	Not Yet Constructed	250 gal	None
GT1 to GT4	GT1E to GT4E	Glycol Tanks #1-4[3]	Not Yet Constructed	1,000 gal	None
FT1	FT1E	Generator Fuel Tank[3]	Not Yet Constructed	25 gal	None
FT2	FT2E	Fire Pump Engine Fuel Tank[3]	Not Yet Constructed	25 gal	None
Fugitive Emission Sources					
EL1	N/A	Equipment Leaks	Not Yet Constructed	N/A	N/A

(1) OC = Oxidation Catalyst; SCR = Selective Catalytic Reduction

(2) BRM has permitted two (2) distinct and independent operational scenarios involving different sets of four (4) Combustion Turbines (CTs). Only one scenario will be permitted for the site. No more than four CTs (of the same set) will be permitted to be operated at the site.

(3) Pursuant to 45CSR13, Table 45-13B, defined as a *de minimis* source but included here for completeness.

(4) Ammonia/Urea are not regulated pollutants but the storage tank is included here for completeness.

1.2. Active R13, R14, and R19 Permits

The underlying authority for any conditions from R13, R14, and/or R19 permits contained in this operating permit is cited using the original permit number (e.g. R13-1234). The current applicable version of such permit(s) is listed below.

Permit Number	Date of Issuance
R13-2896K	August 17, 2023
R13-3493	December 15, 2020

2.0 General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.39.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.1.4. Unless otherwise specified in a permit condition or underlying rule or regulation, all references to a "rolling yearly total" shall mean the sum of the monthly data, values or parameters being measured, monitored, or recorded, at any given time for the previous twelve (12) consecutive calendar months.

2.2. Acronyms

CAAA	Clean Air Act Amendments	**NSPS**	New Source Performance Standards
CBI	Confidential Business Information	**PM**	Particulate Matter
CEM	Continuous Emission Monitor	**PM_{10}**	Particulate Matter less than 10μm in diameter
CES	Certified Emission Statement	**pph**	Pounds per Hour
C.F.R. *or* CFR	Code of Federal Regulations	**ppm**	Parts per Million
CO	Carbon Monoxide	**PSD**	Prevention of Significant Deterioration
C.S.R. *or* CSR	Codes of State Rules	**psi**	Pounds per Square Inch
DAQ	Division of Air Quality	**SIC**	Standard Industrial Classification
DEP	Department of Environmental Protection	**SIP**	State Implementation Plan
FOIA	Freedom of Information Act	**SO_2**	Sulfur Dioxide
HAP	Hazardous Air Pollutant	**TAP**	Toxic Air Pollutant
HON	Hazardous Organic NESHAP	**TPY**	Tons per Year
HP	Horsepower	**TRS**	Total Reduced Sulfur
lbs/hr *or* lb/hr	Pounds per Hour	**TSP**	Total Suspended Particulate
LDAR	Leak Detection and Repair	**USEPA**	United States Environmental Protection Agency
m	Thousand	**UTM**	Universal Transverse Mercator
MACT	Maximum Achievable Control Technology	**VEE**	Visual Emissions Evaluation
mm	Million	**VOC**	Volatile Organic Compounds
mmBtu/hr	Million British Thermal Units per Hour		
$mmft^3$/hr *or* mmcf/hr	Million Cubic Feet Burned per Hour		
NA *or* N/A	Not Applicable		
NAAQS	National Ambient Air Quality Standards		
NESHAPS	National Emissions Standards for Hazardous Air Pollutants		
NO_x	Nitrogen Oxides		

2.3. Permit Expiration and Renewal

2.3.1. Permit duration. This permit is issued for a fixed term of five (5) years and shall expire on the date specified on the cover of this permit, except as provided in 45CSR§30-6.3.b. and 45CSR§30-6.3.c.
[45CSR§30-5.1.b.]

2.3.2. A permit renewal application is timely if it is submitted at least six (6) months prior to the date of permit expiration.
[45CSR§30-4.1.a.3.]

2.3.3. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with 45CSR§30-6.2. and 45CSR§30-4.1.a.3.
[45CSR§30-6.3.b.]

2.3.4. If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.
[45CSR§30-6.3.c.]

2.4. Permit Actions

2.4.1. This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
[45CSR§30-5.1.f.3.]

2.5. Reopening for Cause

2.5.1. This permit shall be reopened and revised under any of the following circumstances:

a. Additional applicable requirements under the Clean Air Act or the Secretary's legislative rules become applicable to a major source with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 45CSR§§30-6.6.a.1.A. or B.

b. Additional requirements (including excess emissions requirements) become applicable to an affected source under Title IV of the Clean Air Act (Acid Deposition Control) or other legislative rules of the Secretary. Upon approval by U.S. EPA, excess emissions offset plans shall be incorporated into the permit.

c. The Secretary or U.S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

d. The Secretary or U.S. EPA determines that the permit must be revised or revoked and reissued to assure compliance with the applicable requirements.

[45CSR§30-6.6.a.]

2.6. Administrative Permit Amendments

2.6.1. The permittee may request an administrative permit amendment as defined in and according to the procedures specified in 45CSR§30-6.4.
[45CSR§30-6.4.]

2.7. Minor Permit Modifications

2.7.1. The permittee may request a minor permit modification as defined in and according to the procedures specified in 45CSR§30-6.5.a.
[45CSR§30-6.5.a.]

2.8. Significant Permit Modification

2.8.1. The permittee may request a significant permit modification, in accordance with 45CSR§30-6.5.b., for permit modifications that do not qualify for minor permit modifications or as administrative amendments.
[45CSR§30-6.5.b.]

2.9. Emissions Trading

2.9.1. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit and that are in accordance with all applicable requirements.
[45CSR§30-5.1.h.]

2.10. Off-Permit Changes

2.10.1. Except as provided below, a facility may make any change in its operations or emissions that is not addressed nor prohibited in its permit and which is not considered to be construction nor modification under any rule promulgated by the Secretary without obtaining an amendment or modification of its permit. Such changes shall be subject to the following requirements and restrictions:

a. The change must meet all applicable requirements and may not violate any existing permit term or condition.

b. The permittee must provide a written notice of the change to the Secretary and to U.S. EPA within two (2) business days following the date of the change. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the permit shield.

d. The permittee shall keep records describing all changes made at the source that result in emissions of regulated air pollutants, but not otherwise regulated under the permit, and the emissions resulting from those changes.

e. No permittee may make any change subject to any requirement under Title IV of the Clean Air Act (Acid Deposition Control) pursuant to the provisions of 45CSR§30-5.9.

f. No permittee may make any changes which would require preconstruction review under any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) pursuant to the provisions of 45CSR§30-5.9.

[45CSR§30-5.9.]

2.11. Operational Flexibility

2.11.1. The permittee may make changes within the facility as provided by § 502(b)(10) of the Clean Air Act. Such operational flexibility shall be provided in the permit in conformance with the permit application and applicable requirements. No such changes shall be a modification under any rule or any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) promulgated by the Secretary in accordance with Title I of the Clean Air Act and the change shall not result in a level of emissions exceeding the emissions allowable under the permit.
[45CSR§30-5.8]

2.11.2. Before making a change under 45CSR§30-5.8., the permittee shall provide advance written notice to the Secretary and to U.S. EPA, describing the change to be made, the date on which the change will occur, any changes in emissions, and any permit terms and conditions that are affected. The permittee shall thereafter maintain a copy of the notice with the permit, and the Secretary shall place a copy with the permit in the public file. The written notice shall be provided to the Secretary and U.S. EPA at least seven (7) days prior to the date that the change is to be made, except that this period may be shortened or eliminated as necessary for a change that must be implemented more quickly to address unanticipated conditions posing a significant health, safety, or environmental hazard. If less than seven (7) days notice is provided because of a need to respond more quickly to such unanticipated conditions, the permittee shall provide notice to the Secretary and U.S. EPA as soon as possible after learning of the need to make the change.
[45CSR§30-5.8.a.]

2.11.3. The permit shield shall not apply to changes made under 45CSR§30-5.8., except those provided for in 45CSR§30-5.8.d. However, the protection of the permit shield will continue to apply to operations and emissions that are not affected by the change, provided that the permittee complies with the terms and conditions of the permit applicable to such operations and emissions. The permit shield may be reinstated for emissions and operations affected by the change:

a. If subsequent changes cause the facility's operations and emissions to revert to those authorized in the permit and the permittee resumes compliance with the terms and conditions of the permit, or

b. If the permittee obtains final approval of a significant modification to the permit to incorporate the change in the permit.

[45CSR§30-5.8.c.]

2.11.4. "Section 502(b)(10) changes" are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.
[45CSR§30-2.40]

2.12. Reasonably Anticipated Operating Scenarios

2.12.1. The following are terms and conditions for reasonably anticipated operating scenarios identified in this permit.

a. Contemporaneously with making a change from one operating scenario to another, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating and to document the change in reports submitted pursuant to the terms of this permit and 45CSR30.

b. The permit shield shall extend to all terms and conditions under each such operating scenario; and

c. The terms and conditions of each such alternative scenario shall meet all applicable requirements and the requirements of 45CSR30.

[45CSR§30-5.1.i.]

2.13. Duty to Comply

2.13.1. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.
[45CSR§30-5.1.f.1.]

2.14. Inspection and Entry

2.14.1. The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

[45CSR§30-5.3.b.]

2.15. Schedule of Compliance

2.15.1. For sources subject to a compliance schedule, certified progress reports shall be submitted consistent with the applicable schedule of compliance set forth in this permit and 45CSR§30-4.3.h., but at least every six (6) months, and no greater than once a month, and shall include the following:

a. Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones or compliance were achieved; and

b. An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measure adopted.

[45CSR§30-5.3.d.]

2.16. Need to Halt or Reduce Activity not a Defense

2.16.1. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.
[45CSR§30-5.1.f.2.]

2.17. Reserved

2.18. Federally-Enforceable Requirements

2.18.1. All terms and conditions in this permit, including any provisions designed to limit a source's potential to emit and excepting those provisions that are specifically designated in the permit as "State-enforceable only", are enforceable by the Secretary, USEPA, and citizens under the Clean Air Act.
[45CSR§30-5.2.a.]

2.18.2. Those provisions specifically designated in the permit as “State-enforceable only” shall become “Federally-enforceable” requirements upon SIP approval by the USEPA.

2.19. Duty to Provide Information

2.19.1. The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records required to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.
[45CSR§30-5.1.f.5.]

2.20. Duty to Supplement and Correct Information

2.20.1. Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.
[45CSR§30-4.2.]

2.21. Permit Shield

2.21.1. Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance provided that such applicable requirements are included and are specifically identified in this permit or the Secretary has determined that other requirements specifically identified are not applicable to the source and this permit includes such a determination or a concise summary thereof.
[45CSR§30-5.6.a.]

2.21.2. Nothing in this permit shall alter or affect the following:

a. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance; or

b. The applicable requirements of the Code of West Virginia and Title IV of the Clean Air Act (Acid Deposition Control), consistent with § 408 (a) of the Clean Air Act.

c. The authority of the Administrator of U.S. EPA to require information under § 114 of the Clean Air Act or to issue emergency orders under § 303 of the Clean Air Act.

[45CSR§30-5.6.c.]

2.22. Credible Evidence

2.22.1. Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defenses otherwise available to the permittee including but not limited to any challenge to the credible evidence rule in the context of any future proceeding.
[45CSR§30-5.3.e.3.B.]

2.23. Severability

2.23.1. The provisions of this permit are severable. If any provision of this permit, or the application of any provision of this permit to any circumstance is held invalid by a court of competent jurisdiction, the remaining permit terms and conditions or their application to other circumstances shall remain in full force and effect.
[45CSR§30-5.1.e.]

2.24. Property Rights

2.24.1. This permit does not convey any property rights of any sort or any exclusive privilege.
[45CSR§30-5.1.f.4]

2.25. Acid Deposition Control

2.25.1. Emissions shall not exceed any allowances that the source lawfully holds under Title IV of the Clean Air Act (Acid Deposition Control) or rules of the Secretary promulgated thereunder.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid deposition control program, provided that such increases do not require a permit revision under any other applicable requirement.

b. No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

c. Any such allowance shall be accounted for according to the procedures established in rules promulgated under Title IV of the Clean Air Act.

[45CSR§30-5.1.d.]

2.25.2. Where applicable requirements of the Clean Air Act are more stringent than any applicable requirement of regulations promulgated under Title IV of the Clean Air Act (Acid Deposition Control), both provisions shall be incorporated into the permit and shall be enforceable by the Secretary and U. S. EPA.
[45CSR§30-5.1.a.2.]

3.0 Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person is prohibited except as noted in 45CSR§6-3.1. **[45CSR§6-3.1.]**

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause or allow any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40 C.F.R. §61.145(b) and 45CSR34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1 State-Enforceable only.]

3.1.5. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2]

3.1.6. **Emission inventory.** The permittee is responsible for submitting, on an annual basis, an emission inventory in accordance with the submittal requirements of the Division of Air Quality.
[W.Va. Code § 22-5-4(a)(15)]

3.1.7. **Ozone-depleting substances.** For those facilities performing maintenance, service, repair or disposal of appliances, the permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 C.F.R. Part 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the prohibitions and required practices pursuant to 40 C.F.R. §§ 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 C.F.R. § 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 C.F.R. § 82.161.

[40 C.F.R. 82, Subpart F]

3.1.8. **Risk Management Plan.** Should this stationary source, as defined in 40 C.F.R. § 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in 40 C.F.R. § 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 C.F.R. Part 70 or 71.
[40 C.F.R. 68]

3.1.9. **Minor Source of Hazardous Air Pollutants (HAP).** HAP emissions from the facility shall be less than 10 tons/year of any single HAP and 25 tons/year of any combination of HAPs. Compliance with this Section shall ensure that the facility is a minor HAP source.
[45CSR13, R13-2896, Condition 4.1.2.]

3.1.10. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.10.; 45CSR13, R13-2896, Condition 4.1.3.; 45CSR13, R13-3493, Condition 4.1.7.d.]

3.1.11. **Maximum Throughput Limitation.** The total maximum combined wet natural gas throughput of the gas processing plant, as processed in a maximum of seven (7) Cryogenic Plants, shall not exceed 1,945 mmscf/day. To demonstrate compliance, the permittee shall maintain records of the amount of natural gas processed in the gas processing plant.
[45CSR§13-5.10.; 45CSR13, R13-2896, Condition 4.1.5.]

3.1.12. No person shall cause, suffer, allow or permit fugitive particulate matter to be discharged beyond the boundary lines of the property on which the discharge originates or at any public or residential location, which causes or contributes to statutory air pollution.
[45CSR§17-3.1.]

3.1.13. When a person is found in violation of 45CSR17, the Director may require the person to utilize a system to minimize fugitive particulate matter. This system to minimize fugitive particulate matter may include, but is not limited to, the following:

a. Use, where practicable, of water or chemicals for control of particulate matter in demolition of existing buildings or structures, construction operations, grading of roads or the clearing of land;

b. Application of asphalt, water or suitable chemicals on unpaved roads, material stockpiles and other surfaces which can create airborne particulate matter;

c. Covering of material transport vehicles, or treatment of cargo, to prevent contents from dripping, sifting, leaking or otherwise escaping and becoming airborne, and prompt removal of tracked material from roads or streets; or

d. Installation and use of hoods, fans and fabric filters to enclose and vent the handling of materials including adequate containment methods during sandblasting, abrasive cleaning or other similar operations.

[45CSR§17-3.2.]

3.1.14. Only the emission unit/source identified in the table titled "Natrium Power Plant" in Section 1.1., with the exception of any *de minimis* sources as identified under Table 45-13B of 45CSR13, is authorized at the permitted Natrium Power Plant by R13-3493. In accordance with the information filed in Permit Application R13-3493, the emission unit/source identified under the table shall not exceed the listed maximum design capacity and comply with any other information provided under the table.
[45CSR13, R13-3493, 4.1.1.]

3.1.15. Upon construction of the equipment in the Emission Units Table specified as "Not Yet Constructed", the permittee shall meet all applicable requirements for the emission units. The permittee shall notify the Secretary, in writing or electronically, of the actual date of the initial startup of these emission units no later than thirty calendar days after such date. Within 180 days of equipment startup, the permittee shall submit, as necessary, a complete application for a significant Title V permit modification pursuant to 45CSR30 to incorporate any amendments or revisions of the applicable requirements.
[45CSR13, R13-2896, Section 2.18.; 45CSR13, R13-3493, Section 2.18.; 45CSR§30-6.5.b.]

3.2. Monitoring Requirements

3.2.1. **Emission Limit Averaging Time.** Unless otherwise specified, compliance with all annual limits shall be based on a rolling twelve-month total. A rolling twelve-month total shall be the sum of the measured parameter of the previous twelve calendar months. Compliance with all hourly emission limits shall be based on the applicable NAAQS averaging times or, where applicable, as given in any approved performance test method.
[45CSR13, R13-2896, Condition 3.2.1.; 45CSR13, R13-3493, Condition 3.2.1.]

3.2.2. **Maximum Design Capacity Compliance.** Compliance with the maximum design capacity limitations as given under Sections 15.1. to 19.1. of this operating permit (Section 4.1. of R13-3493) shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a throughput or production rate that does not exceed the specified value under Section 15.1. to 19.1.
[45CSR13, R13-3493, Condition 4.2.1.]

3.2.3. **Maximum Design Heat Input Compliance.** Compliance with the various combustion unit MDHI limitations as given under Sections 15.1. to 19.1. of this operating permit (Section 4.1. of R13-3493) shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) in question is limited by design to an MDHI that does not exceed the specified value under Sections 15.1. to 19.1.
[45CSR13, R13-3493, Condition 4.2.2.]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or

established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63, if applicable, in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit shall be revised iin accordance with 45CSR§30-6.4. or 45CSR§30-6.5., as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within 60 days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

    1. The permit or rule evaluated, with the citation number and language.

    2. The result of the test for each permit or rule condition.

    3. A statement of compliance or non-compliance with each permit or rule condition.

[WV Code §§ 22-5-4(a)(15-16) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Monitoring information.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

[45CSR§30-5.1.c.2.A.; 45CSR13, R13-2896, Condition 4.1.1.; 45CSR13, R13-3493, Condition 4.4.1.]

3.4.2. **Retention of records.** The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of monitoring sample, measurement, report, application, or record creation date. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Where appropriate, records may be maintained in computerized form in lieu of the above records.
[45CSR§30-5.1.c.2.B.; 45CSR13, R13-2896, Condition 3.4.1.; 45CSR13, R13-3493, Condition 3.4.1.]

3.4.3. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§30-5.1.c. State-Enforceable only.]

3.4.4. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

[45CSR13, R13-2896, Condition 4.1.4.]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.
[45CSR§§30-4.4. *and* 5.1.c.3.D.]

3.5.2. A permittee may request confidential treatment for the submission of reporting required under 45CSR§30-5.1.c.3. pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.
[45CSR§30-5.1.c.3.E.]

3.5.3. Except for the electronic submittal of the annual compliance certification and semi-annual monitoring reports to the DAQ and USEPA as required in 3.5.5 and 3.5.6 below, all notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class or by private carrier with postage prepaid to the address(es), or submitted in electronic format by e-mail as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:

Director
WVDEP
Division of Air Quality
601 57th Street SE
Charleston, WV 25304

US EPA:

Section Chief
U. S. Environmental Protection Agency, Region III
Enforcement and Compliance Assurance Division
Air, RCRA, and Toxics Branch (3ED21)
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2852

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov

[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status reports, Initial Notifications, etc.

3.5.4. **Fees.** The permittee shall pay fees on an annual basis in accordance with 45CSR§30-8.
[45CSR§30-8.]

3.5.5. **Compliance certification.** The permittee shall certify compliance with the conditions of this permit on the forms provided by the DAQ. In addition to the annual compliance certification, the permittee may be required to submit certifications more frequently under an applicable requirement of this permit. The annual certification shall be submitted to the DAQ and USEPA on or before March 15 of each year, and shall certify compliance for the period ending December 31. The permittee shall maintain a copy of the certification on site for five (5) years from submittal of the certification. The annual certification shall be submitted in electronic format by e-mail to the following addresses:

DAQ:	**US EPA:**
DEPAirQualityReports@wv.gov	R3_APD_Permits@epa.gov

[45CSR§30-5.3.e.]

3.5.6. **Semi-annual monitoring reports.** The permittee shall submit reports of any required monitoring on or before September 15 for the reporting period January 1 to June 30 and on or before March 15 for the reporting period July 1 to December 31. All instances of deviation from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with 45CSR§30-4.4. The semi-annual monitoring reports shall be submitted in electronic format by e-mail to the following address:

DAQ:
DEPAirQualityReports@wv.gov

[45CSR§30-5.1.c.3.A.]

3.5.7. **Reserved.**

3.5.8. **Deviations.**

a. In addition to monitoring reports required by this permit, the permittee shall promptly submit supplemental reports and notices in accordance with the following:

1. Reserved.

2. Any deviation that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to the Secretary immediately by telephone or email. A written report of such deviation, which shall include the probable cause of such deviation, and any corrective actions or preventative measures taken, shall be submitted by the responsible official within ten (10) days of the deviation.

3. Deviations for which more frequent reporting is required under this permit shall be reported on the more frequent basis.

4. All reports of deviations shall identify the probable cause of the deviation and any corrective actions or preventative measures taken.

[45CSR§30-5.1.c.3.C.]

b. The permittee shall, in the reporting of deviations from permit requirements, including those attributable to upset conditions as defined in this permit, report the probable cause of such deviations and any corrective actions or preventive measures taken in accordance with any rules of the Secretary. **[45CSR§30-5.1.c.3.B.]**

3.5.9. **New applicable requirements.** If any applicable requirement is promulgated during the term of this permit, the permittee will meet such requirements on a timely basis, or in accordance with a more detailed schedule if required by the applicable requirement. **[45CSR§30-4.3.h.1.B.]**

3.6. Compliance Plan

3.6.1. None

3.7. Permit Shield

3.7.1. The permittee is hereby granted a permit shield in accordance with 45CSR§30-5.6. The permit shield applies provided the permittee operates in accordance with the information contained within this permit.

3.7.2. The following requirements specifically identified are not applicable to the source based on the determinations set forth below. The permit shield shall apply to the following requirements provided the conditions of the determinations are met.

a. 45CSR19 – *Permits for Construction and Major Modification of Major Stationary Sources Which Cause or Contribute to Nonattainment Areas*: This rule establishes a preconstruction permit program for any area designated nonattainment for any national ambient air quality standard (NAAQS) and applies to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment. Marshall County is currently designated as in attainment for the NAAQS. Therefore, 45CSR19 is inapplicable.

b. 45CSR27 – *To Prevent and Control the Emissions of Toxic Air Pollutants*: Natural gas is included as a petroleum product and contains less than 5% benzene by weight. 45CSR§27-2.4. exempts equipment "used in the production and distribution of petroleum products providing that such equipment does not produce or contact materials containing more than 5% benzene by weight."

c. 40 CFR 60, Subparts TTTT and TTTTa – *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*: Per §60.5509(b)(3) and §60.5509a(b)(3), an electric generating unit is not subject to Subpart TTTT or TTTTa if the unit is a combined heat and power unit subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater. Under Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of this operating permit), the amount of power supplied by each turbine to the utility distribution systems is limited to 219,000 MWh per year. Therefore, per §60.5509(b)(3) and §60.5509a(b)(3), the turbines are not subject to Subparts TTTT and TTTTa.

d. 40 CFR 63, Subpart HH – *National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities*: The facility is not subject to the equipment leak standards under 40 CFR §63.769 because it is an area source of HAPs, which limits applicability under Subpart HH to only the (TEG) dehydration unit according to 40 CFR §63.760(b)(2).

Summary of Comments on TitleV-Permit

Page: 25

Number: 1 Author: DWheeler Subject: Comment on Text Date: 6/24/2025 9:44:20 AM

Please add a condition clarifying that any amendments, revisions, or revocations of NSPS OOOOb will supersede the terms and conditions of this permit.

e. 40 CFR 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*: In accordance with 40 CFR §63.7480, this subpart does not apply to the facility since it is not a major source of HAPs as defined in 40 CFR §63.7575.

f. 40 CFR 63, Subpart JJJJJJ – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources*: This subpart does not apply to the facility since the heaters are fueled by natural gas, and gas-fired boilers are exempt per 40 CFR §63.11195(e).

g. 40 CFR 97, Subpart AAAAA/CCCCC/GGGGG – *CSAPR NO_X Annual Trading Program/CSAPR SO_2 Group 1 Trading Program/CSAPR NO_X Ozone Season Group 3 Trading Program*: In accordance with §52.38(a)(2)(i) and §52.39(b), the provisions of 40 CFR 97, Subparts AAAAA and CCCCC are applicable to sources located in West Virginia with regard to emissions occurring in 2015 and each subsequent year; similarly, in accordance with §52.38(b)(2)(iii)(A), the provisions of 40 CFR 97, Subpart GGGGG are applicable to sources located in West Virginia with regard to emissions occurring in 2021 and each subsequent year. Per the applicability criteria of §97.404(a)(1), §97.604(a)(1), and §97.1004(a)(1), the sources considered to be subject to the CSAPR include any stationary, fossil fuel-fired boiler or stationary, fossil fuel-fired combustion turbine serving, at any time on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale. However, §97.404(b)(1)(i), §97.604(b)(1)(i), and §97.1004(b)(1)(i) exempt any unit that otherwise qualifies as a source subject to the CSAPR from Subparts AAAAA, CCCCC, and GGGGG, respectively, if the unit also qualifies as a cogeneration unit throughout the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year after such 12-month period and that does not supply in any calendar year more than one-third of its potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. The turbines TB1A/B through TB4A/B are cogeneration units which produce heat and electricity for use at the facility and, under Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of this operating permit), are subject to a federally enforceable limit that restricts the maximum amount of power supplied by each turbine to the utility distribution system to less than 219,000 MWh per year. Therefore, the facility is not subject to the CSAPR NO_X Trading Program, the CSAPR SO_2 Group 1 Trading Program, nor the CSAPR NO_X Ozone Season Group 3 Trading Program, in accordance with §97.404(b)(1)(i), §97.604(b)(1)(i), and §97.1004(b)(1)(i), respectively.

4.0 Hot Oil Heaters [emission unit ID(s): S001, S016-S019, S052-S053]

4.1. Limitations and Standards

4.1.1. The MDHI of the Hot Oil Heater designated as S001 shall not exceed 216.7 MMBtu/hr and, for each Hot Oil Heater designated as S016-S019 and S052-S053, shall not exceed 61.58 MMBtu/hr. All Hot Oil Heaters (S001, S016-S019, S052-S053) shall be equipped with Low NO_X burners.
[45CSR13, R13-2896, Condition 5.1.1.]

4.1.2. Maximum emissions from the Hot Oil Heaters shall not exceed the following:

a. The maximum emissions from S001 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S001	Nitrogen Oxides	9.75	42.71
	Carbon Monoxide	3.25	14.24
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	1.61	7.07
	$SO_2^{(3)}$	0.15	0.67
	VOCs	0.37	1.61

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2. (condition 4.1.4.b)
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

b. The maximum emissions from each heater S016-S019 and S052-S053 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S016-S019, S052-S053	Nitrogen Oxides	1.48	6.47
	Carbon Monoxide	3.63	15.91
	$SO_2^{(3)}$	0.04	0.19
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.46	2.01
	VOCs	0.33	1.45

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2. (condition 4.1.4.b)
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13, R13-2896, Condition 5.1.2.]

4.1.3. The quantity of natural gas that shall be consumed in the 216.7 MMBtu/hr Hot Oil Heater (S001) shall not exceed 225,571 standard cubic feet per hour and 1,976 x 10^6 standard cubic feet per year. The quantity of

natural gas that shall be consumed in each 61.58 MMBtu/hr Hot Oil Heaters (S016-S019 and S052-S053) shall not exceed 64,101 standard cubic feet per hour and 562 x 10^6 standard cubic feet per year.
[45CSR13, R13-2896, Condition 5.1.3.]

4.1.4. **45CSR2**
Each Hot Oil Heater is subject to the applicable limitations and standards under 45CSR2, including the requirements as given below under a. through c.:

a. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

b. The permittee shall not cause, suffer, allow or permit the discharge of particulate matter into the open air from the fuel burning units, measured in terms of pounds per hour in excess of the amount determined as follows:

1. The product of 0.09 and the total design heat input for the fuel burning units in MMBtu/hr, provided however that no more than 600 lb/hr of particulate matter shall be discharged into the open air.

[45CSR§§2-4.1. and -4.1.2.]

[45CSR13, R13-2896, Condition 5.1.4.]

4.1.5. **40 CFR 60, Subpart Db**
Hot Oil heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db, including the requirements as given below under a. through c.:

a. Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in 40 CFR §60.42b(k)(1).
[45CSR16; 40 CFR §60.42b(k)(2)]

b. Except as provided under 40 CFR §§60.44b(k) and (l), on and after the date on which the initial performance test is completed or is required to be completed under 40 CFR §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of 40 CFR §60.44b and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

1. Low heat release rate: 0.10 lb/MMBtu

2. High heat release rate: 0.20 lb/MMBtu

[45CSR16; 40 CFR §§60.44b(a), (a)(1)(i), and (a)(1)(ii)]

c. Except as provided under 40 CFR §§60.48b(g), (h), and (i), the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs 40 CFR §60.48b(b)(1) or (b)(2).

1. Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system.

[45CSR16; 40 CFR §§60.48b(b) and (b)(1)]

d. Pursuant to 40 CFR §60.49b(r)(2)(iv), the WVDAQ approves quarterly fuel sampling for S001.

[45CSR13, R13-2896, Condition 5.1.5.]

4.1.6. **40 CFR 60, Subpart Dc**
Hot Oil Heaters S016-S019 and S052-S053 are subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated. Recordkeeping and reporting requirements shall be conducted in accordance with §60.48c. These reports shall be submitted in accordance with the timelines and in the order set forth in §60.48c and submitted to the addresses listed in Section 3.5.3.
[45CSR13, R13-2896, Condition 5.1.6.]

4.2. Monitoring Requirements

4.2.1. At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with section 4.1.4. of this permit. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.
[45CSR§2-3.2.; 45CSR13, R13-2896, Condition 5.2.1.]

4.2.2. **40 CFR 60, Subpart Db**
Hot Oil Heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db:

a. For purposes of 40 CFR §60.44b(i), the NO_X standards under 40 CFR §60.44b apply at all times including periods of startup, shutdown, or malfunction.
[45CSR16; 40 CFR §60.44b(h)]

b. Except as provided under 40 CFR §60.44b(j), compliance with the emission limits under 40 CFR §60.44b is determined on a 30-day rolling average basis.
[45CSR16; 40 CFR §60.44b(i)]

c. The CEMS required under 40 CFR §60.48b(b) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
[45CSR16; 40 CFR §60.48b(c)]

d. The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by condition 4.1.5. and required under 40 CFR §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under 40 CFR §60.44b. The 1-hour averages shall be calculated using the data points required under 40 CFR §60.13(h)(2).
[45CSR16; 40 CFR §60.48b(d)]

e. The procedures under 40 CFR §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

1. For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

   i. Except as provided under paragraph e.1.ii. of this condition, NO_X span values shall be determined as follows:

Fuel	Span Values for NO_X (ppm)
Natural Gas	500
Oil	500
Coal	1,000
Mixtures	500 (x + y) + 1,000z

   Where:
   x = Fraction of total heat input derived from natural gas;
   y = Fraction of total heat input derived from oil; and
   z = Fraction of total heat input derived from coal.

   ii. As an alternative to meeting the requirements of paragraph e.1.i. of this condition, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in Appendix A to 40 CFR 75.

2. All span values computed under paragraph e.1.i. of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph e.1.ii. of this section shall be rounded off according to section 2.1.2 in Appendix A to 40 CFR 75.

[45CSR16; 40 CFR §§60.48b(e), (e)(2), and (e)(3)]

f. When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of Appendix A of 40 CFR 60, Method 7A of Appendix A of 40 CFR 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.
[45CSR16; 40 CFR §60.48b(f)]

g. The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

   1. Comply with the provisions of 40 CFR §§60.48b(b), (c), (d), (e)(2), (e)(3), and (f).

   [45CSR16; 40 CFR §§60.48b(g) and (g)(1)]

4.3. Testing Requirements

4.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established under 4.1.2.a. and b.
[45CSR§§2-8.1.2. and -8.1.3.; 45CSR13, R13-2896, Condition 5.3.1.]

4.3.2. **40 CFR 60, Subpart Db**
Hot Oil Heater S001 is subject to the applicable compliance demonstration requirements of 40 CFR 60, Subpart Db:

To determine compliance with the emission limits for NO_X required under 40 CFR §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under 40 CFR §60.8 using the continuous system for monitoring NO_X under 40 CFR §60.48b(b).

a. Following the date on which the initial performance test is completed or required to be completed under 40 CFR §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in 40 CFR §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to 40 CFR §60.48b(g)(1) or (2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

[45CSR16; 40 CFR §§60.46b(c), 60.46b(e), and 60.46b(e)(4)]

4.4. Recordkeeping Requirements

4.4.1. **Records of Fuel Usage**

a. To demonstrate continuous compliance with sections 4.1.1. to 4.1.3., the permittee shall monitor and record the monthly and twelve (12) month rolling total of the amount of natural gas consumed in S001, S016 to S019, and S052 to S053.
[45CSR13, R13-2896, Condition 5.4.1.]

b. The owner or operator shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit in a manner to be established by the Secretary. Such records are to be maintained on-site and made available to the Secretary upon request.
[45CSR§2-8.3.3.]

c. The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified:

1. For fuel burning unit(s) which burn only pipeline quality natural gas, such records shall include, but not be limited to, the date and time of startup and shutdown, and the quantity of fuel consumed on a monthly basis.

[45CSR§§2A-7.1.a. and -7.1.a.1.]

4.4.2. **40 CFR 60, Subpart Db**

Hot Oil Heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db:

a. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.
[45CSR16; 40 CFR §60.49b(d)(1)]

b. The owner or operator of an affected facility subject to the NO_X standards under 40 CFR §60.44b shall maintain records of the following information for each steam generating unit operating day:

1. Calendar date;

2. The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

3. The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

4. Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

5. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

6. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

7. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

8. Identification of the times when the pollutant concentration exceeded full span of the CEMS;

9. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

10. Results of daily CEMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1 of 40 CFR 60.

[45CSR16; 40 CFR §60.49b(g)]

c. The owner or operator of an affected facility who elects to use the fuel-based compliance alternatives in 40 CFR §60.42b or §60.43b shall either:

1. The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in 40 CFR §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in 40 CFR §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

2. The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in 40 CFR §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date of the intended compliance demonstration. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

i. The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

ii. The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

iii. The ratio of different fuels in the mixture; and

iv. The owner or operator can petition the Administrator to approve monthly or quarterly (condition 4.1.5.d.) sampling in place of weekly sampling.

[45CSR16; 40 CFR §§60.45b(k), 60.47b(f), and 60.49b(r)]

d. All records required under 40 CFR §60.49b shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.
[45CSR16; 40 CFR §60.49b(o)]

4.4.3. **40 CFR 60, Subpart Dc**
Hot Oil Heaters S016-S019 and S052-S053 are subject to the following applicable provisions of 40 CFR 60, Subpart Dc:

a. Except as provided under paragraphs b. and c. of this condition, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.
[45CSR16; 40 CFR §60.48c(g)(1)]

b. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in 40 CFR §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(2)]

c. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to 40 CFR 60, Subpart Dc) at that property are natural gas, wood, distillate oil meeting the most current requirements in 40 CFR §60.42c to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(3)]

d. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
[45CSR16; 40 CFR §60.48c(i)]

4.5. Reporting Requirements

4.5.1. Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40 CFR 60, Appendix A, Method 9 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned.
[45CSR13, R13-2896, Condition 5.5.1.]

4.5.2. **40 CFR 60, Subpart Db**
Hot Oil Heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db:

a. The owner/operator is required to submit excess emission reports for any excess emissions that occurred during the reporting period.
[45CSR16; 40 CFR §§60.49b(h), (h)(2), and (h)(2)(i)]

b. For the purposes of 40 CFR §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under 40 CFR §60.46b(e), that exceeds the applicable emission limits in 40 CFR §60.44b.
[45CSR16; 40 CFR §60.49b(h)(4)]

c. The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under 40 CFR §60.48b(b) shall submit reports containing the information recorded under 40 CFR §60.49b(g).
[45CSR16; 40 CFR §60.49b(i)]

d. The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under 40 CFR §§60.49b(h), (i), (j), (k), or (l). The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of 40 CFR 60, Subpart Db was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.
[45CSR16; 40 CFR §60.49b(v)]

e. The reporting period for the reports required under 40 CFR 60, Subpart Db is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.
[45CSR16; 40 CFR §60.49b(w)]

4.6. Compliance Plan

4.6.1. None

5.0 Cryogenic HMO/Stabilizer Heaters [emission unit ID(s): S013, S026, S037, S041, S045, S049, S056]

5.1. Limitations and Standards

5.1.1. **Maximum Design Heat Input.** The maximum design heat input for the Cryogenic HMO Heaters shall not exceed 26.3 MMBtu/hr for units S013, S026, S037, S045, and S049 and 54.67 MMBtu/hr for unit S041. The maximum design heat input for the Stabilizer Heater (S056) shall not exceed 10.09 MMBtu/hr. **[45CSR13, R13-2896, Condition 6.1.1.]**

5.1.2. Maximum emissions from the Cryogenic HMO/Stabilizer Heaters shall not exceed the following:

a. The maximum emissions from Cryogenic HMO Heaters S013, S026, S037, S045, and S049 shall not exceed the following individual unit limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S013 S026 S037 S045 S049	Nitrogen Oxides	2.58	11.29
	Carbon Monoxide	2.17	9.49
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.20	0.86
	$SO_2^{(3)}$	0.02	0.08
	VOCs	0.14	0.62

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

b. The maximum emissions from Cryogenic HMO Heater S041 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S041	Nitrogen Oxides	5.36	23.48
	Carbon Monoxide	4.50	19.72
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.41	1.78
	$SO_2^{(3)}$	0.04	0.17
	VOCs	0.29	1.29

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

c. The maximum emissions from Stabilizer Heater S056 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S056	Nitrogen Oxides	0.99	4.33
	Carbon Monoxide	0.83	3.64
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.08	0.33
	$SO_2^{(3)}$	0.01	0.03
	VOCs	0.05	0.24

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13, R13-2896, Condition 6.1.2.]

5.1.3. To demonstrate compliance with Section 5.1.2., the quantity of natural gas that shall be consumed in each of the 26.3 MMBtu/hr Cryogenic HMO Heaters (S013, S026, S037, S045, S049) shall not exceed 27,377 standard cubic feet per hour and 240×10^6 standard cubic feet per year. The quantity of natural gas that shall be consumed in the 54.67 MMBtu/hr Cryogenic HMO Heater (S041) shall not exceed 56,908 standard cubic feet per hour and 499×10^6 standard cubic feet per year. The quantity of natural gas that shall be consumed in the 10.09 MMBtu/hr Stabilizer Heater (S056) shall not exceed 10,503 standard cubic feet per hour and 92×10^6 standard cubic feet per year.
[45CSR13, R13-2896, Condition 6.1.3.]

5.1.4. **45CSR2**
Each Cryogenic HMO and Stabilizer Heaters is subject to the applicable limitations and standards under 45CSR2, including the requirements as given below under a. amd b.:

a. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six-minute block average.
[45CSR§2-3.1.]

b. The permittee shall not cause, suffer, allow or permit the discharge of particulate matter into the open air from the fuel burning units, measured in terms of pounds per hour in excess of the amount determined as follows:

1. The product of 0.09 and the total design heat input for the fuel burning units in million British Thermal Units (B.T.U.'s) per hour, provided however that no more than six hundred (600) pounds per hour of particulate matter shall be discharged into the open air.

[45CSR§§2-4.1. and -4.1.2.]

[45CSR13, R13-2896, Condition 6.1.4.]

5.1.5. **40 CFR 60, Subpart Dc**

The Cryogenic HMO and Stabilizer Heaters are subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated. Recordkeeping and reporting requirements shall be conducted in accordance with 40 CFR §60.48c. These reports shall be submitted in accordance with the time lines and in the order set forth in 40 CFR §60.48c and submitted to the addresses listed in Section 3.5.3.

[45CSR13, R13-2896, Condition 6.1.5.]

5.2. Monitoring Requirements

5.2.1. At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with section 5.1.4. of this permit. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.

[45CSR13, R13-2896, Condition 6.2.1.]

5.3. Testing Requirements

5.3.1. Compliance with the visible emission requirements of section 5.1.4 shall be determined in accordance with 40 CFR 60, Appendix A, Method 9 or by using measurements from continuous opacity monitoring systems approved by the Secretary. The Secretary may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of section 5.1.4. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.

[45CSR§2-3.2.; 45CSR13, R13-2896, Condition 6.3.1.]

5.3.2. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3 of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established under 5.1.2.a., b., and c.

[45CSR§§2-8.1.2. and -8.1.3.]

5.4. Recordkeeping Requirements

5.4.1. **Records of Fuel Usage**

a. To demonstrate compliance with sections 5.1.1, 5.1.2, and 5.1.3, the permittee shall monitor and record the monthly and twelve-month rolling total of the amount of natural gas consumed in all heaters listed in this section.

[45CSR13, R13-2896, Condition 6.4.1.]

b. The owner or operator shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit in a manner to be established by the Director. Such records are to be maintained on-site and made available to the Director or his duly authorized representative upon request.

[45CSR§2-8.3.3.]

c. The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified:

1. For fuel burning unit(s) which burn only pipeline quality natural gas, such records shall include, but not be limited to, the date and time of startup and shutdown, and the quantity of fuel consumed on a monthly basis.

[45CSR§§2A-7.1.a. and -7.1.a.1.]

5.4.2. The permittee shall maintain records of all monitoring data required by Section 5.2.1 documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s). Should a visible emission observation be required to be performed per the requirements specified in Method 9, the data records of each observation shall be maintained per the requirements of Method 9.
[45CSR13, R13-2896, Condition 6.4.2.]

5.4.3. **40 CFR 60, Subpart Dc**
The Cryogenic HMO and Stabilizer Heaters are subject to the following applicable provisions of 40 CFR 60, Subpart Dc:

a. Except as provided under paragraphs b. and c. of this condition, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.
[45CSR16; 40 CFR §60.48c(g)(1)]

b. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in 40 CFR §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(2)]

c. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to 40 CFR 60, Subpart Dc) at that property are natural gas, wood, distillate oil meeting the most current requirements in 40 CFR §60.42c to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(3)]

d. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
[45CSR16; 40 CFR §60.48c(i)]

5.5. Reporting Requirements

5.5.1. Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40 CFR 60, Appendix A, Method 9 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned. **[45CSR13, R13-2896, Condition 6.5.1.]**

5.6. Compliance Plan

5.6.1. None

6.0 Regeneration Gas Heaters [emission unit ID(s): S012, S024, S036, S040, S044, S048]

6.1. Limitations and Standards

6.1.1. **Maximum Design Heat Input.** The maximum design heat input of the Regeneration Gas Heaters shall not exceed 9.7 MMBtu/hr for units S012, S024, S036, S044, and S048 and 19.28 MMBtu/hr for unit S040. **[45CSR13, R13-2896, Condition 7.1.1.]**

6.1.2. Maximum emissions from the Regeneration Gas Heaters shall not exceed the following:

a. The maximum emissions from units S012, S024, S036, S044, and S048 shall not exceed the following individual unit limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S012 S024 S036 S044 S048	Nitrogen Oxides	0.95	4.17
	Carbon Monoxide	0.80	3.50
	$PM_{2.5}/PM_{10}/PM^{(1)}$	0.07	0.32
	VOCs	0.05	0.23

(1) Includes Condensables.

b. The maximum emissions from unit S040 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S040	Nitrogen Oxides	1.89	8.28
	Carbon Monoxide	1.59	6.95
	$PM_{2.5}/PM_{10}/PM^{(1)}$	0.14	0.63
	VOCs	0.10	0.46

(1) Includes Condensables.

[45CSR13, R13-2896, Condition 7.1.2.]

6.1.3. To demonstrate compliance with Section 6.1.2., the quantity of natural gas that shall be consumed in each of the 9.7 MMBtu/hr Regeneration Gas Heaters (S012, S024, S036, S044, and S048) shall not exceed 10,097 standard cubic feet per hour and 88×10^6 standard cubic feet per year. The quantity of natural gas that shall be consumed in the 19.28 MMBtu/hr Regeneration Gas Heater (S040) shall not exceed 20,069 standard cubic feet per hour and 176×10^6 standard cubic feet per year.
[45CSR13, R13-2896, Condition 7.1.3.]

6.2. Monitoring Requirements

6.2.1. None

6.3. Testing Requirements

6.3.1. None

6.4. Recordkeeping Requirements

6.4.1. To demonstrate compliance with sections 6.1.1., 6.1.2., and 6.1.3., the permittee shall monitor and record the monthly and twelve month rolling total of the amount of natural gas consumed in all heaters listed in this section.
[45CSR13, R13-2896, Condition 7.4.1.]

6.5. Reporting Requirements

6.5.1. None

6.6. Compliance Plan

6.6.1. None

7.0 Fire Pumps [emission unit ID(s): S002, S003, S058]

7.1. Limitations and Standards

7.1.1. The quantity of diesel fuel that shall be consumed in each of the 700 HP diesel-fired fire pump engines, Caterpillar Model C18 (S002, S003) shall not exceed 35.9 gallons per hour and 3,590 gallons per rolling twelve (12) month period during non-emergency use.
[45CSR13, R13-2896, Condition 8.1.1.]

7.1.2. Maximum emissions from each of the 700 HP diesel-fired fire pumps, Caterpillar Model C18 (S002, S003) shall not exceed the following limits for the entire life of the engine:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S002 S003	NMHC + Nitrogen Oxides(1)	4.63	0.23
	Carbon Monoxide(1)	4.01	0.20
	$PM_{2.5}/PM_{10}/PM$(1)(2)	0.23	0.01
	Volatile Organic Compounds	4.63	0.23

(1) Calculated using emission limits in Table 4 of 40 CFR 60, Subpart IIII
(2) Includes Condensables
[45CSR16; 40 CFR §§60.4205(c) and 60.4206; Table 4 of 40 CFR 60, Subpart IIII; 45CSR13, R13-2896, Conditions 8.1.2. and 8.1.5.]

7.1.3. **Maximum Annual Operation Limitation.** The maximum yearly hours of operation for each of the 700 HP diesel-fired fire pump engine(s)/generator(s), Caterpillar Model C18 (S002, S003) and for each additional fire pump engine added as authorized under 7.1.8. shall not exceed an annual limit of 100 hours of non-emergency use as recorded with a non-resettable hour meter. Compliance with each Maximum Yearly Operation Limitation shall be determined using a twelve (12) month rolling total. A twelve (12) month rolling total shall mean the sum of the hours of operation at any given time during the previous twelve consecutive calendar months for each engine.
[45CSR13, R13-2896, Condition 8.1.4.]

7.1.4. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to 40 CFR 60, Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.
[45CSR16; 40 CFR §60.4207(b)]

7.1.5. **40 CFR 63, Subpart ZZZZ**
S002, S003, and S058 are each subject to all applicable regulations given under 40 CFR 63, Subpart ZZZZ including the following:

a. *Stationary RICE subject to Regulations under 40 CFR 60.* An affected source that meets any of the criteria in paragraphs 40 CFR §§63.6590(c)(1) through (7) must meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60,

Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under 40 CFR 63.

[45CSR34; 40 CFR §63.6590(c); 45CSR13, R13-2896, Condition 8.1.6.]

7.1.6. The permittee must satisfy the following compliance requirements:

a. If the permittee is an owner or operator and must comply with the emission standards specified in 40 CFR 60, Subpart IIII, the permittee must do all of the following, except as permitted under paragraph d. of this section:

1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

2. Change only those emission-related settings that are permitted by the manufacturer; and

3. Meet the requirements of 40 CFR 1068, as they apply to the permittee.

b. The permittee shall comply with the emission standards specified in 40 CFR §60.4205(c) by purchasing an engine certified to the emission standards. The unit must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph d. of this condition.

c. If the permittee owns or operates an emergency stationary ICE, the permittee must operate the emergency stationary ICE according to the requirements in paragraphs c.1. through 3. of this condition. In order for the engine to be considered an emergency stationary ICE, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs c.1. through 3. of this condition, is prohibited. If the permittee does not operate the engine according to the requirements in paragraphs c.1. through 3. of this condition, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.

1. There is no time limit on the use of emergency stationary ICE in emergency situations.

2. The permittee may operate the emergency stationary ICE for the purpose specified in paragraph c.2.i. of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph c.3. of this condition counts as part of the 100 hours per calendar year allowed by this paragraph c.2.

i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

3. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph c.2. of this section.

Except as provided in paragraph c.3.i. of this condition, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

i. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

a. The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

b. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

c. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

d. The power is provided only to the facility itself or to support the local transmission and distribution system.

e. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

d. If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as follows:

1. If the permittee is an owner or operator of a stationary CI internal combustion engine greater than 500 HP, the permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after changing emission-related settings in a way that is not permitted by the manufacturer. The permittee must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[45CSR16; 40 CFR §§60.4211(a), (c), (f), (g), and (g)(3)]

7.1.7. The permittee shall comply with the General Provisions of 40 CFR 60, specified in Table 8 of 40 CFR 60, Subpart IIII.
[45CSR16; 40 CFR §60.4218(a)]

7.1.8. In addition to S002 and S003, the permittee is authorized to construct and operate an additional fire pump engine/generator or multiple engines/generators (S058) not to exceed an aggregate mechanical boilerplate rating of 3,000 HP and to be fired only by diesel. The aggregate quantity of diesel fuel that shall be consumed in the additional engines shall not exceed 153.9 gallons per hour and 15,386 gallons per rolling twelve (12) month period during non-emergency use. The aggregate emissions from the additional fire pumps shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S058	Nitrogen Oxides	31.75	1.59
	Carbon Monoxide	17.26	0.86
	$PM_{2.5}/PM_{10}/PM^{(1)}$	0.99	0.05
	Volatile Organic Compounds	31.75	1.59

(1) Includes Condensables.

[45CSR13, R13-2896, Condition 8.1.3.]

7.1.9. The fire pump engine/generator or multiple engines/generators (S058) are each subject to all applicable regulations given under 40 CFR 60, Subpart IIII including the following:

a. Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 to Subpart IIII, for all pollutants.

Maximum Engine Power	Model Year(s)	NMHC + NO_X g/kW-hr (g/HP-hr)	CO g/kW-hr (g/HP-hr)	PM g/kW-hr (g/HP-hr)
kW > 560 (HP > 750)	2008+	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

[45CSR16; 40 CFR §60.4205(c) and Table 4 of 40 CFR 60, Subpart IIII; 45CSR13, R13-2896, Condition 8.1.5.]

7.1.10. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR §§60.4204 and 60.4205 for the entire life of the engine.
[45CSR16; 40 CFR §60.4206]

7.2. Monitoring Requirements

7.2.1. The permittee must install a non-resettable meter to monitor hours of operation.
[45CSR16; 40 CFR §60.4209(a)]

7.2.2. As the annual fuel usage limitations given under 7.1.1. and 7.1.8. above are based on the maximum hourly design capacity fuel usage rates and 100 hours of operation, compliance with the annual fuel usage limitations is based on compliance with 7.1.3.
[45CSR13, R13-2896, Condition 8.2.1.]

7.3. Testing Requirements

7.3.1. Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to 40 CFR 60, Subpart IIII must do so according to 40 CFR §§60.4212(a) through (e).
[45CSR16; 40 CFR §60.4212]

7.4. Recordkeeping Requirements

7.4.1. If the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
[45CSR16; 40 CFR §60.4214(b)]

7.5. Reporting Requirements

7.5.1. If an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in 40 CFR §60.4211(f)(3)(i), the permittee must submit an annual report according to the requirements in paragraphs a. through c. of this section.

a. The report must contain the following information:

i. Company name and address where the engine is located.

ii. Date of the report and beginning and ending dates of the reporting period.

iii. Engine site rating and model year.

iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

v. Hours spent for operation for the purposes specified in 40 CFR §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

b. The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

c. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to 40 CFR 60, Subpart IIII is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR §60.4. Beginning on February 26, 2025, submit annual report electronically according to 40 CFR §60.4214(g).

[45CSR16; 40 CFR §60.4214(d)]

7.5.2. If required to submit notifications or reports following the procedure specified in this paragraph, the permittee must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information claimed as CBI.
[45CSR16; 40 CFR §60.4214(g)]

7.6. Compliance Plan

7.6.1. None

8.0 Glycol Dehydration Units [emission unit ID(s): S006]

8.1. Limitations and Standards

8.1.1. The maximum aggregate wet natural gas throughput to Glycol Dehydration Unit S006 shall not exceed 460 mmscf/day or 167,900 mmscf/year.
[45CSR13, R13-2896, Condition 10.1.1.]

8.1.2. The maximum glycol recirculation rate in the Glycol Dehydration Unit (S006) shall not exceed 40 gallons per minute limit.
[45CSR13, R13-2896, Condition 10.1.2.]

8.1.3. The maximum aggregate controlled emissions generated from the Glycol Dehydration Unit (S006), including the still vent and the flash tank, but not including the combustion exhaust emissions from the Reboiler, shall not exceed the limits given in the following table:

a. Glycol Dehydration Unit S006:

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
VOCs	1.78	7.80
n-Hexane	*0.04*	*0.17*
Benzene	*0.03*	*0.13*
Toluene	*0.05*	*0.23*
Xylene	*0.03*	*0.13*
Total HAPs	0.15	0.66

(1) Emissions based on GLYCalc Version 4.0 using wet gas throughputs as limited under 8.1.1. and a 10% safety factor (on uncontrolled emissions).

[45CSR13, R13-2896, Condition 10.1.3.]

8.1.4. Still vent and flash tank vapors from S006 shall be routed to the Hot Oil Heater (S001: C001) and used as fuel.
[45CSR13, R13-2896, Condition 10.1.4.]

8.1.5. **40 CFR 63, Subpart HH: Exemptions**
Exemptions. The owner or operator of an area source is exempt from the requirements of 40 CFR §63.764(d) if the criteria listed in 40 CFR §§63.764(e)(1)(i) or (ii) are met, except that the records of the determination of these criteria must be maintained as required in 40 CFR §63.774(d)(1).

a. The actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere are less than 0.90 megagram per year, as determined by the procedures specified in 40 CFR §63.772(b)(2).

[45CSR13, R13-2896, Condition 10.1.5.; 45CSR34; 40 CFR §§63.764(e)(1) and (e)(1)(ii)]

8.1.6. The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph a. or b. of this condition. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

a. The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI-GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1); or

b. The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in 40 CFR §§63.772(a)(1)(i) or (ii), or an alternative method according to 40 CFR §63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

[45CSR34; 40 CFR §63.772(b)(2)]

8.1.7. Any source that determines it is not a major source but has actual emissions of 5 tons per year or more of a single HAP, or 12.5 tons per year or more of a combination of HAPs (i.e., 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination and each year thereafter, using gas composition data measured during the preceding 12 months.
[45CSR34; 40 CFR §63.760(c)]

8.1.8. At all times the owner or operator must 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[45CSR34; 40 CFR §63.764(j)]

8.2. Monitoring Requirements

8.2.1. For the purposes of demonstrating compliance with the maximum wet gas throughput limit set forth in 8.1.1., the permittee shall monitor and maintain monthly and rolling twelve-month records of the wet gas throughput of the Glycol Dehydration Unit.
[45CSR13, R13-2896, Condition 10.2.1.]

8.2.2. Compliance with the Maximum Glycol Recirculation limitation set forth in 8.1.2. shall be determined using an average of a minimum of quarterly readings of the actual glycol pump(s) rate. If more than one pump is operating simultaneously then the rate of each operating pump shall be recorded and totaled for compliance purposes.
[45CSR13, R13-2896, Condition 10.2.2.]

8.2.3. Representative gas sample collection and analysis frequency for the dehydration unit shall be determined as set forth in the schedule provided in the following table:

Wet Gas Sampling and Analysis Frequency for Dehydration Units Based on Potential HAP Emission Rates	
Each dehydration unit exempt from §63.764(d) requirements and with federally enforceable controls	Upon request by the Secretary.
Each dehydration unit exempt from §63.764(d) requirements and without federally enforceable controls	An initial compliance evaluation within 180 days of registration issuance or within 180 days of startup of the dehydration unit, whichever is later.

[45CSR13, R13-2896, Condition 10.2.3.]

8.3. Testing Requirements

8.3.1. The permittee shall sample wet natural gas in accordance with the Gas Processor Association (GPA) Method 2166 and analyze the samples in accordance with GPA Method 2286. The permittee may utilize other equivalent methods provided they are approved in advance by DAQ as part of a testing protocol. If alternative methods are proposed, a test protocol shall be submitted for approval no later than 60 days before the scheduled test date.

Note: The DAQ defines a representative wet gas sample to be one that is characteristic of the average gas composition dehydrated throughout a calendar year. If an isolated sample is not indicative of the annual average composition, then a company may opt to produce a weighted average based on throughput between multiple sampling events, which can be used to define a more representative average annual gas composition profile.

[45CSR13, R13-2896, Condition 10.3.1.]

8.4. Recordkeeping Requirements

8.4.1. The permittee shall maintain records of the actual average benzene emissions (in terms of benzene emissions per year) as determined in accordance with 40 CFR §63.772(b)(2).
[45CSR34; 40 CFR §63.774(d)(1)(ii)]

8.5. Reporting Requirements

8.5.1. The TEG dehydration units are located at an area source and each meets the criteria in 40 CFR §63.764(e)(1)(ii). Therefore, the permittee is exempt from the reporting requirements for area sources specified in 40 CFR §§63.775(c)(1) through (7).
[45CSR34; 40 CFR §§63.775(c) and (c)(8)]

8.6. Compliance Plan

8.6.1. None

9.0 40 CFR 60, Subparts Kb and Kc Storage Tanks [emission unit ID(s): TK-802, TK-2802, TK-3802, TK-4802, TK-5802, TK-6802, TK-7802, VRU]

9.1. Limitations and Standards

9.1.1. Each of the Natural Gasoline Storage Tanks (TK-802, TK-2802, TK-3802, TK-4802, TK-5802, and TK-6802) will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from these tanks shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.
[45CSR13, R13-2896, Condition 12.1.1.]

9.1.2. The Refrigerated Propane Storage Tank (TK-7802) shall utilize the VRU to recapture propane product that flashes-off from the storage tank, re-condense the product, and then route it back to the storage tank.
[45CSR13, R13-2896, Condition 12.1.2.]

9.1.3. The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for each storage tank listed in this section.
[45CSR13, R13-2896, Condition 12.1.3.]

9.1.4. The Natural Gasoline Storage Tanks TK-802 and TK-2802 are subject to all applicable requirements of 40 CFR 60, Subpart Kb including the following:

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:
[45CSR16; 40 CFR §60.112b(a)]

1. A closed vent system and control device meeting the following specifications:

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in 40 CFR 60, Subpart VV, §60.485(b).
[45CSR16; 40 CFR §60.112b(a)(3)(i)]

ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (40 CFR §60.18) of the General Provisions.
[45CSR16; 40 CFR §60.112b(a)(3)(ii)]

[45CSR13, R13-2896, Condition 12.1.4.] (TK-802 and TK-2802)

9.1.5. The owner or operator of each source that is equipped with a closed vent system and control device as required in 40 CFR §60.112b(a)(3) or (b)(2) (other than a flare) is exempt from 40 CFR §60.8 of the General Provisions and shall meet the following requirements.

a. Submit for approval by the Administrator as an attachment to the notification required by 40 CFR §60.7(a)(1) or, if the facility is exempt from 40 CFR §60.7(a)(1), as an attachment to the notification required by 40 CFR §60.7(a)(2), an operating plan containing the information listed below.

1. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under 40 CFR 60, Subpart Kb, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816°C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

2. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

b. Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph a. of this condition, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

[45CSR16; 40 CFR §60.113b(c)] (TK-802 and TK-2802)

9.1.6. The Natural Gasoline Storage Tanks TK-3802 through TK-6802 and the Refrigerated Propane Storage Tank TK-7802 are subject to all applicable requirements of 40 CFR 60, Subpart Kc including the following:

a. All standards including emission limitations shall apply at all times, including periods of startup, shutdown, and malfunction. As provided in 40 CFR §60.11(f), 40 CFR §60.110c(g) supersedes the exemptions for periods of startup, shutdown, and malfunction in Subpart A of 40 CFR 60.
[45CSR16; 40 CFR §60.110c(g)] (TK-3802 through TK-7802)

b. **General storage vessel control requirements.** The permittee must equip and operate each storage vessel affected facility meeting the thresholds in 40 CFR §60.110c(c)(1) as specified in paragraphs b.1. and b.2. of this condition.

1. For TK-3802 to TK-6802, the permittee has elected to install and operate a closed vent system routed to a fuel gas system as specified in 40 CFR §60.112c(d).

2. For TK-7802, the permittee has elected to install and operate a closed vent system routed to a process as specified in 40 CFR §60.112c(d).

[45CSR16; 40 CFR §§60.112c(a) and (a)(1)] (TK-3802 through TK-7802)

c. For each storage vessel affected facility complying with the closed vent system routed to a control device, fuel gas system, or process provisions specified in 40 CFR §60.112(d) regardless of size and for

each storage vessel with a design capacity greater than or equal to 1,000,000 gallons containing a volatile organic liquid (VOL) that, as stored, has a maximum true vapor pressure equal to or greater than 1.5 psia, the permittee must comply with the requirements in 40 CFR §60.112c(e).
[45CSR16; 40 CFR §60.112c(a)(3)] (TK-3802 through TK-7802)

d. The permittee must meet the applicable testing, monitoring, and inspection requirements specified in 40 CFR §60.113c, recordkeeping requirements specified in 40 CFR §60.115c, and reporting requirements specified in 40 CFR §60.116c.
[45CSR16; 40 CFR §60.112c(a)(4)] (TK-3802 through TK-7802)

9.1.7. **Requirements for closed vent system routed to a fuel gas system or process.** The permittee must design, install, and operate each affected storage vessel with a closed vent system that routes to a fuel gas system or process as specified in paragraphs a. through c. of this condition.

a. The storage vessel must be designed and operated to be routed through a closed vent system to a fuel gas system or process at all times the storage vessel contains VOL without venting to the atmosphere through either meeting the storage vessel design requirements specified in paragraph a.1. of this condition or the vapor recovery system design requirements specified in paragraph a.2. of this condition. Compliance with this requirement must be demonstrated according to paragraph a.3. of this condition. Any vacuum breaking device on the storage vessel must close while the storage vessel is still under vacuum of at least -0.1 inches of water (-0.0036 psig or -0.025 kPa gauge).

1. The storage vessel must be designed to operate at a gauge pressure of no less than 1 psi greater than the maximum true vapor pressure of the stored liquid and any back pressure anticipated when the storage vessel is filled at its maximum rate without venting to the atmosphere.

2. The vapor recovery system must be designed and operated to maintain the pressure in each storage vessel routed to a control device below the venting pressure of that storage vessel.

3. The permittee must equip each pressure relief device and vacuum breaking device on a storage vessel with a device(s) or use a monitoring system that is capable of meeting the requirements in paragraphs a.3.i. through iii. of this condition. If all emissions from a pressure relief device are routed through a closed vent system to a control device, process, or fuel gas system, then the permittee is not required to comply with the requirements of this paragraph a.3.

i. Identifying the pressure release.

ii. Recording the time and duration of each pressure release.

iii. Notifying operators immediately that a pressure release is occurring. The device or monitoring system must be either specific to the pressure relief device or vacuum breaking device itself or must be associated with each storage vessel to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

b. Except for closed vent systems operated and maintained under negative pressure, each closed vent system must meet the requirements specified in paragraphs b.1. through 3. of this condition.

1. The closed vent system must be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 parts per million by volume (ppmv) above background, as determined using Method 21 of Appendix A-7 to 40 CFR 60 as specified in 40 CFR §§60.113c(c)(2) and (3), and as determined by observations for visible, audible, and olfactory indications of leaks. Visible, audible, and olfactory inspections must be performed quarterly and Method 21 of Appendix A-7 instrument monitoring must be conducted at least annually.

2. Except for pressure relief devices and except for open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR §§60.482-6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR §§60.482-6(a)(2), (b), and (c), the permittee must comply with the provisions of either paragraph b.2.i. or ii. of this condition for each closed vent system that contains bypass lines that could divert a vent stream to the atmosphere.

    i. Properly install, maintain, and operate a flow indicator that is capable of taking readings every 15 minutes. Install the flow indicator at the entrance to any bypass line.

    ii. Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration.

3. The permittee must equip each pressure relief device on a closed vent system with a device(s) or use a monitoring system that is capable of meeting the requirements in paragraphs b.3.i. through iii. If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, process, or fuel gas system, then the permittee is not required to comply with the requirements of this paragraph b.3.

    i. Identifying the pressure release.

    ii. Recording the time and duration of each pressure release.

    iii. Notifying operators immediately that a pressure release is occurring. The device or monitoring system must be either specific to the pressure relief device itself or must be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

c. If emissions are routed from a storage vessel to a fuel gas system or process, the permittee must meet the requirements in paragraphs c.1. through 4. of this condition, as applicable.

1. The fuel gas system or process must be operating at all times when emissions from an affected storage vessel are routed to it.

2. If all emissions are routed to a process, the VOL in the emissions must meet one or more of the conditions specified in paragraphs c.2.i. through iv. of this condition and the permittee must comply with the compliance determination requirements in paragraph c.3. of this condition.

i. Recycled and/or consumed in the same manner as a material that fulfills the same function in that process.

ii. Transformed by chemical reaction into materials that are not regulated materials.

iii. Incorporated into a product.

iv. Recovered.

3. To demonstrate compliance with paragraph c.2. of this condition for an affected storage vessel, the permittee must prepare a design evaluation (or engineering assessment) that demonstrates the extent to which one or more of the conditions specified in paragraphs c.2.i. through iv. of this are being met.

4. If emissions from an affected storage vessel are routed to a fuel gas system, the permittee must submit the statement of connection for fuel gas systems specified in 40 CFR §60.116c(a)(7).

[45CSR16; 40 CFR §§60.112c(d)(1), (d)(2), and (d)(6)] (TK-3802 through TK-7802)

9.1.8. **Requirements for storage vessel degassing.** For each storage vessel meeting the specifications in 40 CFR §60.112c(a)(3), the permittee must meet the requirements in paragraphs a. and b. of this condition during emptying and degassing of a storage vessel until the vapor space concentration in the storage vessel is less than 10 percent of the lower explosive limit (LEL) or, for nonflammable liquids, 5,000 ppmv as methane. The permittee must determine the LEL or methane concentration using process instrumentation or a portable measurement device and follow procedures for calibration and maintenance according to manufacturer's specifications. The permittee must check instrument calibration and check the instrumental offset response each day the instrument is used and prior to discontinuing controlled degassing to confirm the accuracy of the instrument's readings.

a. Remove liquids from the storage vessel as much as practicable. Chemicals or a diluent such as a distillate fuel may be introduced into the storage vessel for the purpose of reducing vapor concentration before or during active degassing.

b. Comply with the following:

1. Reduce total VOC emissions by routing emissions to a fuel gas system or process and meet the requirements specified in 40 CFR §60.112c(d)(6).

[45CSR16; 40 CFR §§60.112c(e), (e)(1), and (e)(2)(iii)] (TK-3802 through TK-7802)

9.2. Monitoring Requirements

9.2.1. To demonstrate compliance with section 9.1.3., the permittee shall monitor the vapor recovery unit system in accordance with the plans and specifications and manufacturer's recommendations.
[45CSR13, R13-2896, Condition 12.2.1.]

9.2.2. For each storage vessel subject to the provision in 40 CFR §60.112c(a), the permittee must meet the requirements of paragraph a. of this condition if emissions are routed through a closed vent system to a fuel

Page: 56

Number: 1 Author: DWheeler Subject: Comment on Text Date: 6/24/2025 9:02:30 AM
Please also include the compliance options provided in 40 CFR 60.112c(e)(2)(i) and 40 CFR 60.112c(e)(2)(ii).

gas system or process. The permittee must also meet the applicable requirements of paragraph b. of this condition.

a. **Monitoring of the closed vent system**. For each source that is equipped with a closed vent system and routes to a fuel gas system or process to meet the requirements in 40 CFR §60.112c(d), the permittee must conduct monitoring and inspections of the closed vent system as specified in paragraph a.1. of this condition and repair leaks as specified in paragraph a.2. of this condition.

1. For each closed vent system, the permittee must conduct the instrument monitoring in paragraphs a.1.i. through iii. of this condition. The permittee must conduct the initial instrument monitoring within 180 days of an affected facility being connected to the closed vent system. Subsequent instrument inspections must be conducted within 365 days of the previous inspection. Visual, audible, and olfactory inspections must be conducted quarterly.

i. Conduct instrument monitoring using the procedures in Method 21 of Appendix A-7 to 40 CFR 60. The detection instrument must meet the performance criteria of Method 21 of Appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 of Appendix A-7 must be for the average composition of the fluid and not for each individual organic compound in the stream. For streams that contain nitrogen, air, water, or other inerts that are not organic VOC, the representative stream response factor must be determined on an inert-free basis. The instrument reading that defines a leak is 500 ppmv (as methane). The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of Appendix A-7. The calibration gases in paragraph a.1.i.a. and b. of this condition must be used. The drift assessment specified in paragraph a.1.i.c. of this condition must be performed at the end of each monitoring day.

a. Zero air (less than 10 ppm of hydrocarbon in air).

b. A mixture of methane in air at a concentration of approximately 500 ppmv.

c. At the end of each monitoring day, check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of Appendix A-7 to 40 CFR 60, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage. If a calibration drift assessment shows a negative drift of more than 10 percent, then re-monitor all equipment monitored since the last calibration with instrument readings between the leak definition and the leak definition multiplied by (100 minus the percent of negative drift) divided by 100. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the leak definition and below the leak definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

ii. Any parts of the closed vent system that are designated as unsafe to inspect are exempt from the inspection requirements of paragraph a.1.i. of this section if the conditions of paragraph a.1.ii.a. and b. of this condition are met.

a. The owner or operator determines that the equipment is unsafe-to-inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraph a.1.i. of this condition; and

b. The owner or operator has a written plan that requires inspection of the equipment as frequently as practical during safe-to-inspect times. Inspection is not required more than once annually.

iii. Any parts of the closed vent system that are designated as difficult-to-inspect are exempt from the inspection requirements of paragraph a.1.i. of this section if the provisions of paragraphs a.1.iii.a. and b. apply.

a. The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters (7 feet) above a support surface; and

b. The owner or operator has a written plan that requires inspection of the equipment at least once every 60 calendar months.

2. Leaks, as indicated by an instrument reading greater than 500 ppmv or emissions detected by visible, audible, and olfactory methods, shall be repaired as soon as practical following the requirements outlined in paragraphs a.2.i. and ii. of this condition.

i. Except as allowed by paragraph a.2.ii. of this condition, a first attempt at repair shall be made no later than 5 days after the leak is detected. Repairs shall be completed no later than 15 days after the leak is detected or at the beginning of the next introduction of vapors to the system, whichever is later.

ii. Delay of repair of a closed vent system for which leaks have been detected is allowed if repair within 15 days after a leak is detected is technically infeasible or unsafe or if the owner or operator determines that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed as soon as practical.

b. **Requirements for determining maximum true vapor pressure.** For each affected storage vessel, the permittee must determine the maximum true vapor pressure of the stored VOL according to the requirements specified in paragraphs b.1. and 2. of this condition. For storage vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For storage vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

1. Prior to the initial filling of the storage vessel or to the refilling of the storage vessel with a new VOL, the highest maximum true vapor pressure for the range of anticipated liquids to be stored, including mixtures for which the permittee can define the range of concentrations for constituents in the mixture or with a known maximum Reid vapor pressure, must be determined using any one of the methods described in paragraphs b.1.i. through iv. of this condition.

i. As obtained from standard reference texts.

ii. ASTM D6377-20 (incorporated by reference; see 40 CFR §60.17). Perform the method using a vapor-to-liquid ratio of 4:1, which is expressed in the method as VPCR.

iii. ASTM D6378-22 (incorporated by reference; see 40 CFR §60.17). Perform the method using a vapor-to-liquid ratio of 4:1.

iv. As measured by an appropriate method as approved by the Administrator.

2. For each affected storage vessel storing a mixture of indeterminate composition or a mixture of unknown variable composition, the initial determination of the vapor pressure required by paragraph b.1. of this condition must be a physical test using one of the methods specified in paragraphs b.1.ii. through iv. of this condition. Additional physical tests using one of the methods specified in paragraphs b.1.ii. through iv. of this condition are required at least once every 6 calendar months thereafter as long as the measured vapor pressure remains below the applicable thresholds in 40 CFR §§60.110c(c)(1), (c)(2), (d)(1), or (d)(2). If the vapor pressure measured under this paragraph b.2. exceeds the threshold defined in 40 CFR §60.110c(c)(1), (c)(2), (d)(1), or (d)(2), the permittee must meet the requirements in 40 CFR §60.112c and the corresponding requirements in 40 CFR §§60.113c through 60.116c. If the storage vessel does not have controls meeting the requirements in 40 CFR §60.112c, the storage vessel must be emptied and taken out of service until controls meeting the requirements in 40 CFR §60.112c can be installed. Upon compliance with the provisions in 40 CFR §60.112c, no additional vapor pressure monitoring is required.

[45CSR16; 40 CFR §§60.113c(c), (c)(2), (c)(3), and (d)] (TK-3802 through TK-7802)

9.3. Testing Requirements

9.3.1. None

9.4. Recordkeeping Requirements

9.4.1. **Record of Maintenance of Vapor Recovery Unit.** The permittee shall maintain accurate records of the vapor recovery unit equipment inspection and/or preventative maintenance procedures.
[45CSR13, R13-2896, Condition 12.3.1.]

9.4.2. **Record of Malfunction of Vapor Recovery Unit.** The permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the vapor recovery unit during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

[45CSR13, R13-2896, Condition 12.3.2.]

9.4.3. After installing control equipment in accordance with 40 CFR §§60.112b(a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

The permittee shall keep copies of all records required by this section, except for the record required by 9.4.3.a., for at least two years. The record required by 9.4.3.a. will be kept for the life of the control equipment.

a. A copy of the operating plan.

b. A record of the measured values of the parameters monitored in accordance with 40 CFR §60.113b(c)(2).

[45CSR16; 40 CFR §§60.115b and 60.115b(c)] (TK-802 and TK-2802)

9.4.4. The permittee must comply with the following recordkeeping requirements:

a. The permittee shall keep copies of all records required by 40 CFR 60, Subpart Kb, except for the record required by 9.4.4.b., for at least 2 years. The record required by 9.4.4.b. will be kept for the life of the source.

b. The owner or operator of each storage vessel as specified in 40 CFR §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

[45CSR16; 40 CFR §§60.116b(a) and (b)] (TK-802 and TK-2802)

9.4.5. **Recordkeeping requirements under 40 CFR 60, Subpart Kc**

a. Except as otherwise specified in paragraphs b. through d. of this condition, the permittee must keep copies of all records required by 40 CFR §60.115c and all reports required under 40 CFR §60.116c for at least 5 years.

b. For each storage vessel affected facility as specified in 40 CFR §60.110c(a), the permittee must keep readily accessible records for the life of the source showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

c. Each vessel equipped with a closed vent system routed to a control device, fuel gas system, or process meeting the specification of 40 CFR §60.112c(d) is exempt from the requirements of 40 CFR §60.115c(c).

d. For each storage vessel as specified in 40 CFR §60.112c(a), the permittee must keep records as required in 40 CFR §§60.115c(d)(1) through (5), as applicable depending upon the control equipment installed to meet the requirements of 40 CFR §60.112c.

1. After installing a closed vent system routed to a fuel gas system or process to comply with the provisions in 40 CFR §60.112c(d), the permittee must keep the following records, as well as the records in 40 CFR §§60.115c(d)(4) and (5), as applicable.

i. Monitoring for the closed vent system conducted under 40 CFR §60.113c(c)(2), including the date of inspection.

ii. The written plan(s) required under 40 CFR §§60.113c(c)(2)(ii) and (iii) for unsafe-to-inspect and difficult-to-inspect portions of the closed vent system.

iii. For each leak detected during the monitoring conducted under 40 CFR §§60.113c(c)(2) and (3), the permittee must record: the date the leak was detected; the location of the leak; the method used to detect the leak (Method 21 of Appendix A-7 to 40 CFR 60 or visible, audible, and olfactory methods); and the maximum concentration reading obtained by Method 21 of Appendix A-7, if applicable. For each repair attempt, the permittee must record: the date of each repair attempt; the actions taken to repair the leak during each repair attempt; and date the repair was completed. If the repair is delayed, the permittee must record the reason for the delay and the date the repair is expected to be completed.

iv. For each bypass line, maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out.

v. For each pressure relief device or vacuum breaking device on a storage vessel or closed vent system required to be monitored according to 40 CFR §60.112c(d)(1)(iii) or (d)(2)(iii): the device type; the monitoring device or system used for the device; data from the device or system indicating whether a pressure release occurred; and the date, time, and duration of each pressure release, if applicable.

e. For storage vessels required to meet the degassing requirements in 40 CFR §60.112c(a)(3), the permittee must maintain records necessary to demonstrate compliance with the requirements in 40 CFR §60.112c(e) including, if appropriate, records of existing standard site procedures used to empty and degas (deinventory) equipment for safety purposes.

[45CSR16; 40 CFR §§60.115c(a), (b), (c)(2), (d), (d)(3), (d)(3)(iii) to (vii), and (e)] (TK-3802 through TK-7802)

9.5. Reporting Requirements

9.5.1. Upon request by the Director, the permittee shall report deviations within a requested time from any occurrences when the control device was operated outside of the parameters defined in the monitoring plan. **[45CSR13, R13-2896, Condition 12.3.3.]**

9.5.2. **Initial notification requirements for 40 CFR 60, Subpart Kc.** The permittee must submit initial notifications to the Administrator within 60 days after becoming an affected storage vessel, ~~whichever is later.~~ Once the report template for 40 CFR 60, Subpart Kc has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, the permittee must submit all subsequent initial notifications using the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart Kc and following the procedure specified in 40 CFR §60.116c(f). The date report templates become available will be listed on the CEDRI website. For each storage vessel affected facility subject to the standards in 40 CFR §60.112c, include the following information in the initial notification:

a. The following general facility information:

1. Facility name;

2. Facility physical address, including city, county, state, and zip code.

3. Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places; and

4. The following information for the facility contact person:

i. Name;

ii. Mailing address, including city, county, state, and zip code;

iii. Telephone number; and

iv. Email address.

b. Identification of the storage vessel(s) subject to 40 CFR 60, Subpart Kc.

c. Capacity (in gallons) of each storage vessel.

d. Maximum true vapor pressure of the liquid stored (in psia) in each storage vessel.

e. Indication of the standards for which the storage vessel complies [40 CFR §§60.112c(b); 60.112c(c); 60.112c(d); 60.112c(e)].

f. If emissions are routed to a process, submit the information specified in 40 CFR §§60.112c(d)(6)(ii) and (iii).

g. If emissions are routed to a fuel gas system, as specified in 40 CFR §60.112c(d)(6)(iv), submit a statement that the emission stream is connected to the fuel gas system.

[45CSR16; 40 CFR §§60.116c(a), (a)(1) to (a)(5), (a)(7), and (a)(8)] (TK-3802 through TK-7802)

Page: 62

Number: 1 Author: DWheeler Subject: Cross-Out Date: 6/24/2025 9:13:33 AM

9.5.3. **Reporting requirements for semiannual reports under 40 CFR 60, Subpart Kc.**

a. **Semiannual reports under 40 CFR 60, Subpart Kc.** The permittee must submit to the Administrator semiannual reports with the applicable information in 40 CFR §§60.116c(c)(1) through (12) by the dates specified in 40 CFR §60.116c(d). For 40 CFR 60, Subpart Kc, the semiannual reports supersede the excess emissions and monitoring systems performance report and/or summary report form required under 40 CFR §60.7. Once the report template for 40 CFR 60, Subpart Kc has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, the permittee must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart Kc and following the procedure specified in 40 CFR §60.116c(f). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in 40 CFR 60, Subpart Kc, regardless of the method in which the report is submitted.

1. Report the following general facility information:

i. Facility name;

ii. Facility physical address, including city, county, and state;

iii. Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places;

iv. The following information for the facility contact person:

a. Name;

b. Mailing address;

c. Telephone number; and

d. Email address.

v. Date of report and beginning and ending dates of the reporting period. The permittee is no longer required to provide the date of report when the report is submitted via CEDRI; and

vi. Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

2. After installing a closed vent system that routes to a fuel gas system, or process to comply with 40 CFR §60.112c, report the following.

i. For each inspection conducted under 40 CFR §60.113c(c)(2), identification of the closed vent system, the date of inspection, the type of inspection (Method 21 of Appendix A-7 to 40 CFR 60 or visible, audible, and olfactory methods) and summary result of the inspection (no leaks detected or leaks were detected). For each leak detected, provide an identification of the part

of the closed vent system associated with the leak, the date of the first attempt at repair, and the date of successful repair or anticipated repair if the repair is delayed.

ii. The start date and time, duration in hours, and an estimate of the mass quantity in pounds of VOL released for times when flow is detected or emissions are diverted from the control device through a bypass line while a storage vessel affected facility vented to the closed vent system contains VOL or is being degassed.

3. For pressure relief devices on a storage vessel or closed vent system subject to 40 CFR §60.112c(d)(1)(iii) or (d)(2)(iii), report each pressure release to the atmosphere, including pressure relief device identification name or number, the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released.

4. For vacuum breaking devices on a storage vessel subject to 40 CFR §§60.112c(d) and (d)(1)(iii), report the following information for each time the vacuum breaking device failed to close prior to the storage vessel reaching atmospheric pressure: identification name or number of vacuum breaking device; the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released.

b. **Timeframe for semiannual report submissions.**

1. The first semiannual report will cover the period starting with the date the source becomes an affected facility subject to 40 CFR 60, Subpart Kc and ending June 30 or December 31, whichever date is earlier. For example, if the source becomes an affected facility on April 15, the first semiannual report would cover the period from April 15 to June 30. The first semiannual report must be submitted on or before the last day of the month 2 months after the last date covered by the semiannual report. In this example, the first semiannual report would be due August 31.

2. Subsequent semiannual reports will cover subsequent 6 calendar month periods (January 1 through June 30 or July 1 through December 31, as applicable) with each report due on or before the last day of the month 2 months after the last date covered by the semiannual report (August 31 or February 28 or 29, as applicable).

3. For each affected facility that is subject to permitting regulations pursuant to 40 CFR 70 or 71, if the delegated authority has established dates for submitting semiannual reports pursuant to 40 CFR §70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent semiannual reports according to the dates the delegated authority has established instead of the dates in paragraphs b.1. and 2. of this condition.

[45CSR16; 40 CFR §§60.116c(c), (c)(1), (c)(8), (c)(8)(ii), (c)(8)(iii), (c)(11), (c)(12), and (d)] (TK-3802 through TK-7802)

9.5.4. **Requirements for electronically submitting reports under 40 CFR 60, Subpart Kc.** For notifications or reports that must be submitted following the procedures specified in 40 CFR §60.116c(f), the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information claimed as confidential business information (CBI).
[45CSR16; 40 CFR §60.116c(f)]

9.6. Compliance Plan

9.6.1. None

10.0 Flare [emission unit ID(s): S004A]

10.1. Limitations and Standards

10.1.1. The permittee shall utilize a non-assisted Callidus CAL-MP staged, multi-point ground flare system (with a maximum aggregate pilot light heat input of 1.629 MMBtu/hr), designated as S004A, for control of potential emissions from maintenance events, equipment blowdowns, pressure relief valves, and other controlled sources. The flare shall have a maximum design capacity of 19.8 mmscf/hr.
[45CSR13, R13-2896, Condition 13.1.1.]

10.1.2. The Flare (S004A) shall operate according to the following requirements:

a. Maximum aggregate combustion exhaust emissions (not including uncombusted pass-through emissions of VOCs) from operation of the Flare (including those contributed by the pilot light) shall not exceed the following during routine maintenance events, equipment blowdowns, from pressure relief valves, and other controlled sources:

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
Nitrogen Oxides	1,539.61	14.61
Carbon Monoxide	3,073.64	29.17
$PM_{2.5}/PM_{10}/PM^{(1)}$	30.66	0.50
VOCs	22.19	0.36

(1) Compliance with this limit will ensure compliance with 45CSR§6-4.1 (Condition 10.1.4.a.).

b. Based on the minimum VOC destruction and removal efficiency (DRE) of 98.0% as given under 10.1.6., maximum emissions of uncombusted pass-through VOCs and HAPs (generated during routine maintenance events, equipment blowdowns, and from pressure relief valves) emitted at the Flare (as uncombusted pass-through emissions) shall not exceed 10,153 lb/hr and 39.38 ton/year of VOCs and 4.53 lb/hr and 0.12 ton/year of HAPs.

[45CSR13, R13-2896, Condition 13.1.2.]

10.1.3. The total heat input of waste gases sent to the Flare during routine pigging events, equipment and site-wide blowdowns, the ethane treater flash tanks, irregular process vents, and from the closed vent system shall not exceed 197,459 MMBtu per rolling twelve-month period.
[45CSR13, R13-2896, Condition 13.1.3.]

10.1.4. The Flare is subject to 45CSR6. The requirements of 45CSR6 include but are not limited to the following:

a. No person shall cause, suffer, allow or permit particulate matter to be discharged from any incinerator into the open air in excess of the quantity determined by use of the following formula:

$$Emissions\ (lb/hr)\ = F\ \times Incinerator\ Capacity\ (ton/hr)$$

Where, the factor, F, is either 5.43 for an incinerator with a capacity of less than 15,000 lb/hr or 2.72 for an incinerator with a capacity of 15,000 lb/hr or greater.

[45CSR§6-4.1.]

b. No person shall cause, suffer, allow or permit emission of smoke into the atmosphere from any incinerator which is twenty (20%) percent opacity or greater.
[45CSR§6-4.3.]

c. The provisions of 45CSR§6-4.3. shall not apply to smoke which is less than forty percent (40%) opacity, for a period or periods aggregating no more than eight (8) minutes per start-up, or six (6) minutes in any sixty (60)-minute period for stoking operations.
[45CSR§6-4.4.]

d. No person shall cause or allow the emission of particles of unburned or partially burned refuse or ash from any incinerator which are large enough to be individually distinguished in the open air.
[45CSR§6-4.5.]

e. Incinerators, including all associated equipment and grounds, shall be designed, operated and maintained so as to prevent the emission of objectionable odors.
[45CSR§6-4.6.]

f. At such reasonable times as the Secretary may designate, the operator of any incinerator shall be required to conduct or have conducted stack tests to determine the particulate matter loading, by using 40 CFR 60, Appendix A, Method 5 or other equivalent U.S. EPA approved method approved by the Secretary, in exhaust gases. Such tests shall be conducted in such manner as the Secretary may specify and be filed on forms and in a manner acceptable to the Secretary. The Secretary may, at the Secretary's option, witness or conduct such stack tests. Should the Secretary exercise his or her option to conduct such tests, the operator will provide all the necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment such as scaffolding, railings and ladders to comply with generally accepted good safety practices.
[45CSR§6-7.1.]

g. The Secretary may conduct such other tests as the Secretary may deem necessary to evaluate air pollution emissions other than those noted above.
[45CSR§6-7.2.]

[45CSR13, R13-2896, Condition 13.1.4.]

10.1.5. A pilot flame must be present at all times of operation of the Flare. The presence of a pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
[45CSR13, R13-2896, Condition 13.1.5.]

10.1.6. The Flare shall be operated and designed in accordance with the information filed in permit application R13-2896F to achieve a VOC DRE of 98.0%.
[45CSR13, R13-2896, Condition 13.1.7.]

10.1.7. The inlet gas flow rate of the Flare must be equal to or less than the maximum specified by the manufacturer.
[45CSR13, R13-2896, Condition 13.1.8.]

10.2. Monitoring Requirements

10.2.1. In order to demonstrate compliance with the requirements of 10.1.2., 10.1.3., and 10.1.4.a., the permittee shall monitor the aggregate throughput and heat input of waste gases sent to the Flare on a monthly basis.
[45CSR13, R13-2896, Condition 13.2.1.]

10.2.2. To demonstrate compliance with the emission limits of 10.1.2. and the flame requirements of 10.1.5., the presence of a flame shall be continuously monitored using a duplex thermocouple or any other equivalent device to detect the presence of a flame. The presence or absence of the flame shall be recorded in the facility's data acquisition system at 15-minute intervals. The absence of the pilot flame shall be defined as an excursion per the CAM Plan under 40 CFR Part 64.
[45CSR13, R13-2896, Condition 13.2.2.; 45CSR§30-5.1.c.; 40 CFR §64.6(c)]

10.2.3. The permittee shall meet the following Visible Emissions Requirements for the Ground Flare:

a. To demonstrate compliance with the visible emissions requirements of 45CSR6, the permittee shall conduct the following visible emission checks and/or opacity monitoring and recordkeeping for the Ground Flare:

1. The visible emission check shall determine the presence or absence of visible emissions. The observations shall be conducted according to Section 11 of EPA Method 22. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training may be obtained from written materials found in the References 1 and 2 from 40 CFR 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR 60, Appendix A, Method 9 certification course. The observation period (Section 11 of EPA Method 22) shall be a minimum of one (1) hour each calendar month during flaring operation;

2. As the Ground Flare is of smokeless design, any observation of visible emissions will indicate incorrect operation of the flare. Therefore, upon the observation of visible emissions, the permittee shall, at the next available safe opportunity, cease operation of the flare and attempt to correct the problem. After an attempt to correct the problem, the permittee shall then conduct a minimum of one (1) hour of visible emissions observations according to 10.2.3.a. during the flare operation;

3. The permittee shall maintain records of all monitoring data required by 10.2.3. documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s);

4. Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40 CFR 60, Appendix A, Method 9 or 22 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned.

[45CSR13, R13-2896, Condition 13.2.3.]

10.2.4. **Proper maintenance.** At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[45CSR§30-5.1.c.; 40 CFR §64.7(b)]

10.2.5. **Continued operation.** Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of 40 CFR Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[45CSR§30-5.1.c.; 40 CFR §64.7(c)]

10.2.6. **Response to excursions or exceedances.**

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[45CSR§30-5.1.c.; 40 CFR §64.7(d)]

10.2.7. **Documentation of need for improved monitoring.** After approval of monitoring under 40 CFR Part 64, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for

which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the part 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[45CSR§30-5.1.c.; 40 CFR §64.7(e)]

10.2.8. **Quality Improvement Plan (QIP) Requirements.** Based on the results of a determination made under 40 CFR §64.7(d)(2), the Administrator or the permitting authority may require the permittee to develop and implement a QIP. If required, the QIP shall be developed and implemented in accordance with 40 CFR §§64.8(b) through (e).
[45CSR§30-5.1.c.; 40 CFR §64.8]

10.3. Testing Requirements

10.3.1. None

10.4. Recordkeeping Requirements

10.4.1. For the purpose of demonstrating compliance with Sections 10.1.5. and 10.2.2., the permittee shall maintain records of the times and duration of all periods which the pilot flame was absent.
[45CSR13, R13-2896, Condition 13.2.4.]

10.4.2. **General recordkeeping requirements.**

a. The owner or operator shall comply with the recordkeeping requirements specified in 40 CFR §70.6(a)(3)(ii). The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 CFR §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 CFR Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[45CSR§30-5.1.c.; 40 CFR §64.9(b)]

10.5. Reporting Requirements

10.5.1. If the permittee is required by the Director to demonstrate compliance with sections 10.1.4.f. and 10.1.4.g., then the permittee shall submit a testing protocol at least thirty (30) days prior to testing and shall submit a notification of the testing date at least fifteen (15) days prior to testing. The permittee shall submit the testing results within sixty (60) days of testing and provide all supporting calculations and testing data.
[45CSR13, R13-2896, Condition 13.2.5.]

10.5.2. Any deviation(s) from the flare design and operation criteria in Section 10.1.6. and permit application R13-2896F, shall be reported in writing to the Director as soon as practicable, but no later than ten (10) calendar days following discovery of such deviation.
[45CSR13, R13-2896, Condition 13.2.6.]

10.5.3. The permittee shall report to the Director, the time, cause of event, estimate of emissions and corrective actions taken when the Ground Flare was used for an emergency at the facility.
[45CSR13, R13-2896, Condition 13.2.7.]

10.5.4. **General reporting requirements.**

a. On and after the date specified in 40 CFR §64.7(a) by which the owner or operator must use monitoring that meets the requirements of 40 CFR Part 64, the owner or operator shall submit monitoring reports to the permitting authority in accordance with 40 CFR §70.6(a)(3)(iii).

b. A report for monitoring under 40 CFR Part 64 shall include, at a minimum, the information required under 40 CFR §70.6(a)(3)(iii) and the following information, as applicable:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

3. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[45CSR§30-5.1.c.; 40 CFR §64.9(a)]

10.6. Compliance Plan

10.6.1. None

11.0 Ethane Amine Units [emission unit ID(s): S011, S054]

11.1. Limitations and Standards

11.1.1. **Maximum Throughput Limitation.** The maximum sour ethane throughput to each individual Ethane Amine Unit shall not exceed 129 mmscf/day and 47,085 mmscf/year (or, alternatively 81,523 barrels/day and 29,755,895 barrels/year of treated ethane). Compliance with the Maximum Throughput Limitation shall be determined using a twelve-month rolling total. A twelve-month rolling total shall mean the sum of the monthly throughput at any given time during the previous twelve consecutive calendar months.
[45CSR13, R13-2896, Condition 14.1.1.]

11.1.2. Each Ethane Amine Unit (S011, S054) shall be designed and operated in accordance with the following:

a. Carbon dioxide will be removed from the ethane product in an amine contacting system;

b. The total ethane product shall be contacted with an amine solution in the Amine Contactor where the carbon dioxide in the ethane product is removed to less than 500 ppmw;

c. The rich amine from the Contactor is regenerated in the Amine Regenerator where heat input is used to drive the carbon dioxide and water overhead. Overheads from S011 are vented to the atmosphere and overheads from S054 are routed as described in Condition 11.1.15.; and

d. The lean amine from the bottom of the Regenerator is recycled back to the Amine Contactor.

[45CSR13, R13-2896, Condition 14.1.2.]

11.1.3. Off gas from both Ethane Amine Units' flash tanks shall be collected and sent to the Ground Flare (S004A) for combustion.
[45CSR13, R13-2896, Condition 14.1.3.]

11.1.4. Maximum methanol and VOC emissions from Ethane Amine Unit S011 shall not exceed 1.82 lb/hr and 7.99 ton/year, and 1.98 lb/hr and 8.67 ton/year, respectively.
[45CSR13, R13-2896, Condition 14.1.4.]

11.1.5. The still vent emissions from S054 shall be, at a minimum of 95% of time the unit is in operation, captured by the vapor recovery unit (VRU) and routed to the residue gas discharge line. During VRU downtime, emissions from S054 still vent shall vent to atmosphere. Maximum methanol and VOC emissions from Ethane Amine Unit S054 shall not exceed 1.82 lb/hr and 0.40 ton/year, and 1.98 lb/hr and 0.43 ton/year, respectively.
[45CSR13, R13-2896, Condition 14.1.5.]

11.2. Monitoring Requirements

11.2.1. In order to show compliance with 11.1.1., the permittee shall either: (1) monitor and record the monthly and twelve-month total throughput of sour ethane fed to both Ethane Amine Units, or (2) monitor and record the monthly and twelve-month total throughput of total treated ethane from both Ethane Amine Units.
[45CSR13, R13-2896, Condition 14.2.1.]

11.2.2. The permittee shall monitor and record the monthly and twelve-month total percentage of time Ethane Amine Unit S054 is operated when the VRU is not in operation.
[45CSR13, R13-2896, Condition 14.2.2.]

11.3. Testing Requirements

11.3.1. The permittee shall conduct, at a minimum of once per twelve-month period, sampling of the inlet gas stream to the Ethane Amine Units. The results of this test shall be used, with appropriate modeling techniques (such as use of ProMax software), to verify that the emissions of the unit are in compliance with those given under 11.1.4. and 11.1.5. above.
[45CSR13, R13-2896, Condition 14.2.3.]

11.4. Recordkeeping Requirements

11.4.1. None

11.5. Reporting Requirements

11.5.1. None

11.6. Compliance Plan

11.6.1. None

12.0 Other Storage Tanks and Liquids Loading/Unloading [emission unit ID(s): TK-906, TK-2906, TK-907, TK-2907, S008, S015, S033, S055, L-1]

12.1. Limitations and Standards

12.1.1. The maximum design capacity of material loading/unloading and maximum associated emissions shall not exceed the following for the specific NGLs:

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)	VOC Emissions	
					lb/hr	ton/year
S008	Propane	3,600 (vb)	4,000 (vb)	4,000 (vb)	5.99	4.21
	Isobutane			No		
	Butanes			No		
	NGL			No		
	Natural Gasoline	600 (vb)	2,000 (vb)	N/A		
S033	Natural Gasoline	N/A	N/A	4,000	97.22	82.69
S015	Slop Oil/Produced Water	150	No	No	2.32	0.11
L-1	Gasoline Dispenser	20 (gal/hr)	No	No	0.18	0.072
S055	Pressurized NGL/Condensate (Unloading)	3,600	N/A	No	6.64	14.54

[45CSR13, R13-2896, Condition 15.1.1.]

12.1.2. The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.
[45CSR13, R13-2896, Condition 15.1.2.]

12.1.3. The main Liquids Loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutane, butanes, natural gasoline, or NGLs to truck or railcar ***and*** when loading propane to barge. Natural Gasoline barge loading (S033) operations, and Slop Oil/Produced Water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.
[45CSR13, R13-2896, Condition 15.1.3.]

12.1.4. All truck loading of Slop Oil and Produced Water shall be done using the submerged-fill method. The "submerged-fill method" shall, for the purposes of this permit, mean either bottom-filling or filling by extending the pipe to near the bottom of the tank, and as soon as is practicable, below the level of liquid.
[45CSR13, R13-2896, Condition 15.1.4.]

12.1.5. The maximum annual throughput and VOC emissions for the specified tanks shall not exceed what is given in the following table:

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-L-1	Gasoline(1)	12,000	0.13
TK-906	Slop Oil	248,712	0.05
TK-907	Produced Water	754,824	0.14
TK-2906	Slop Oil	248,712	0.05
TK-2907	Produced Water	754,824	0.14

(1) This is purchased retail gasoline, not natural gasoline as produced on site.

[45CSR13, R13-2896, Condition 15.1.5.]

12.2. Monitoring Requirements

12.2.1. None

12.3. Testing Requirements

12.3.1. None

12.4. Recordkeeping Requirements

12.4.1. To demonstrate compliance with sections 12.1.2. and 12.1.5., the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas (S008, S033, S055) and in the specified storage tanks.
[45CSR13, R13-2896, Condition 15.2.1.]

12.5. Reporting Requirements

12.5.1. None

12.6. Compliance Plan

12.6.1. None

13.0 Pigging Operations [emission unit ID(s): S034, S035]

13.1. Limitations and Standards

13.1.1. The permittee shall utilize a non-assisted flare, designated as S034, for control of potential emissions during all times of propane pig trap operations. The flare will have a maximum design capacity of 72,000 scf/hr and be designed and operated to achieve a minimum propane DRE of 98%.
[45CSR13, R13-2896, Condition 16.1.1.]

13.1.2. The maximum annual combustion of waste gases in the pig trap flare (S034) shall not exceed 720,000 scf. The maximum number of pigging events per year for all pig traps shall not exceed the limits and volumes per event (scf) established in the permit application R13-2896G.
[45CSR13, R13-2896, Condition 16.1.2.]

13.1.3. Maximum combustion exhaust emissions (not including uncombusted pass-through emissions of waste gases) from S034 shall not exceed the following:

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
Nitrogen Oxides	24.25	0.12
Carbon Monoxide	13.99	0.07
$PM_{2.5}/PM_{10}/PM$	1.31	0.01

[45CSR13, R13-2896, Condition 16.1.3.]

13.1.4. Based on the minimum VOC DRE of 98.0% as required under 13.1.1., maximum emissions of uncombusted VOCs emitted at the Pigging Flare shall not exceed 227.77 lb/hr and 1.14 ton/year of VOCs. The maximum emissions of VOCs and HAPs emitted from all other pigging operations with the exception of the propane pig trap shall not exceed 103.10 lb/hr and 0.84 ton/year, and 1.25 lb/hr and 0.01 ton/year, respectively.
[45CSR13, R13-2896, Condition 16.1.4.]

13.1.5. The Pigging Flare shall be designed and operated in accordance with 40 CFR §60.18.
[45CSR13, R13-2896, Condition 16.1.6.]

13.1.6. The Pigging Flare is subject to 45CSR6. The requirements of 45CSR6 include but are not limited to those given under condition 10.1.4.
[45CSR13, R13-2896, Condition 16.1.7.]

13.1.7. The pigging vapors from the three (3) truck side 30” Inlet Receivers shall be captured by the VRU and routed back to the process.
[45CSR13, R13-2896, Condition 16.1.5.]

13.2. Monitoring Requirements

13.2.1. In order to show compliance with 13.1.2., the permittee shall calculate, based on the information collected under 13.2.2., the throughput (in scf) of waste gases fed to S034 on a monthly and a rolling twelve-month basis.
[45CSR13, R13-2896, Condition 16.2.1.]

13.2.2. In order to show compliance with 13.1.2., the permittee shall monitor and record the total number and type of pigging events and the estimated volume per event (in scf) on a monthly and rolling twelve-month total for all pig traps.
[45CSR13, R13-2896, Condition 16.2.2.]

13.2.3. The permittee shall meet the following Visible Emissions Requirements for the S034:

a. To demonstrate compliance with the visible emissions requirements of 45CSR6, the permittee shall conduct the following visible emission checks and/or opacity monitoring and recordkeeping for the Pigging Flare:

1. The visible emission check shall determine the presence or absence of visible emissions. The observations shall be conducted according to Section 11 of EPA Method 22. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training may be obtained from written materials found in the References 1 and 2 from 40 CFR 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR 60, Appendix A, Method 9 certification course. The observation period shall be a minimum of one (1) hour at initial commissioning and at least one (1) hour thereafter each calendar year during a pig trap flaring operation. In the event no pig trap flaring operations occurred during the calendar year, the permittee shall not be required to complete a Method 22 observation for that year;

2. As the Pigging Flare is of smokeless design, any observation of visible emissions will indicate incorrect operation of the flare. Therefore, upon the observation of visible emissions, the permittee shall, at the next available safe opportunity, cease operation of the flare and attempt to correct the problem. After an attempt to correct the problem, the permittee shall then conduct a minimum of one (1) hour of visible emissions observations according to 13.2.3.a.1. during the next pig trap flaring operation; and

3. The permittee shall maintain records of all monitoring data required by 13.2.3. documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s).

[45CSR13, R13-2896, Condition 16.2.3.]

13.3. Testing Requirements

13.3.1. None

13.4. Recordkeeping Requirements

13.4.1. None

13.5. Reporting Requirements

13.5.1. None

13.6. Compliance Plan

13.6.1. None

14.0 40 CFR 60, Subparts OOOO, OOOOa, and OOOOb Requirements [emission unit ID(s):FUG AREA 1 through 7 and Compressors]

14.1. Limitations and Standards

FUG AREA 1 through 4

14.1.1. In accordance with the request given in Permit Application R13-2896K, the permittee shall operate FUG AREA 1 through 4 in accordance with all applicable requirements given under 40 CFR 60, Subpart OOOOa, even those areas that are eligible to comply with 40 CFR 60, Subparts KKK and OOOO.
[45CSR13, R13-2896, Condition 17.1.1.]

14.1.2. This condition applies to the group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant.

a. The permittee must comply with the requirements of 40 CFR §§60.482-1a(a), (b), (d), and (e), 60.482-2a, and 60.482-4a through 60.482-10a, except as provided in 40 CFR §60.5401a.

b. The permittee must comply with the provisions of 40 CFR §60.485a except as provided in 40 CFR §60.5400a(f).

c. The permittee must comply with the provisions of 40 CFR §§60.486a and 60.487a except as provided in 40 CFR §§60.5401a, 60.5421a, and 60.5422a.

d. The permittee must use the following provision instead of 40 CFR §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in 40 CFR §60.17) must be used.

[45CSR16; 40 CFR §§60.5400a(a) and (d) to (f)]

FUG AREA 5 through 7

14.1.3. This section applies to process unit equipment affected facilities located at an onshore natural gas processing plant. The permittee must comply with the requirements of 40 CFR §§60.5400b(a) through (l) to reduce methane and VOC emissions from equipment leaks, except as provided in 40 CFR §60.5402b. As an alternative to the standards in this section, the permittee may comply with the requirements in 40 CFR §60.5401b.

a. **General standards.** The permittee must comply with the requirements in paragraphs b. through d. of this condition for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable. The permittee must comply with the requirements in paragraph e. of this condition for each open-ended valve

or line. The permittee must comply with the requirements in paragraph f. of this condition for each closed vent system and control device used to comply with equipment leak provisions in this condition. The permittee must comply with paragraph g. of this condition for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. The permittee must make repairs as specified in paragraph h. of this condition. The permittee must demonstrate initial compliance with the standards as specified in paragraph i. of this condition. The permittee must demonstrate continuous compliance with the standards as specified in paragraph j. of this condition. The permittee must perform the reporting as specified in paragraph k. of this condition. The permittee must perform the recordkeeping as required in paragraph l. of this condition.

1. The permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in 40 CFR 60, Subpart OOOOb according to the requirements of 40 CFR §60.5399b.

2. Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of Appendix A-6 to 40 CFR 60. Alternatively, if the piece of equipment is in wet gas service, the permittee may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see 40 CFR §60.17).

b. **Monitoring surveys.** The permittee must monitor for leaks using OGI in accordance with Appendix K of 40 CFR 60, unless otherwise specified in paragraphs c. or d. of this condition.

1. Monitoring surveys must be conducted bimonthly.

2. Any emissions observed using OGI are defined as a leak.

c. **Additional requirements for pumps in light liquid service.** In addition to the requirements in paragraph b., the permittee must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal, except as specified in paragraphs c.3. and 4. of this condition. If there are indications of liquids dripping from the pump seal, the permittee must follow the procedure specified in either paragraph c.1. or 2. of this condition.

1. Monitor the pump within 5 calendar days using OGI in accordance with Appendix K or the methods specified in 40 CFR §60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 2,000 ppmv or greater is provided using Method 21 of Appendix A-7 to 40 CFR 60.

2. Designate the visual indications of liquids dripping as a leak and repair the leak as specified in paragraph h. of this condition.

3. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph f. of this condition, it is exempt from the weekly inspection requirements in paragraph c. of this condition.

4. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph c. of this condition, provided that each pump is visually inspected as often as practicable and at least bimonthly.

d. **Additional requirements for pressure relief devices in gas/vapor service.** In addition to the requirements in paragraph b. of this condition, the permittee must monitor each pressure relief device as specified in paragraph d.1. of this condition, except as specified in paragraph d.2. of this condition.

1. The permittee must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks using the methods specified in 40 CFR §60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 500 ppmv or greater is provided using Method 21 of Appendix A-7 to 40 CFR 60.

2. Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph f. of this condition is exempt from the requirements of paragraph d.1. of this condition.

e. **Open-ended valves or lines.** Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs e.4. and 5. of this condition. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

1. If evidence of a leak is found at any time by audible, visual, and olfactory (AVO), or any other detection method, a leak is detected.

2. Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

3. 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 shall remain closed at all other times.

4. 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 the requirements of 40 CFR §60.5400b.

5. 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 as specified in paragraphs e. introductory text, e.2., and e.3. are exempt from the requirements of this section.

f. **Closed vent systems and control devices.** Closed vent systems used to comply with the equipment leak provisions of this condition must comply with the requirements in 40 CFR §§60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this condition must comply with the requirements in 40 CFR §§60.5412b, 60.5415b(f), and 60.5417b.

g. **Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.** If evidence of a potential leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph h. of this condition.

h. **Repair requirements.** When a leak is detected, the permittee must comply with the requirements of paragraphs h.1. through 5. of this condition, except as provided in paragraph h.6. of this condition.

1. A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on equipment may be removed after it has been repaired.

2. A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected. A first attempt at repair is not required if the leak is detected using OGI and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

i. First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs h.2.i.a. and b. of this condition, where practicable.

a. Tightening the packing gland nuts.

b. Ensuring that the seal flush is operating at design pressure and temperature.

ii. For each valve where a leak is detected, the permittee must comply with paragraphs h.2.ii.a., b. or c., and d. of this condition.

a. Repack the existing valve with a low-e packing.

b. Replace the existing valve with a low-e valve; or

c. Perform a drill and tap repair with a low-e injectable packing.

d. An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

3. Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraphs h.4., 5., and 6 of this condition.

4. If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, the permittee must make the repair within 5 calendar days of detection.

5. If the repair for AVO or other indication of a leak for open-ended valves or lines; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, the permittee must make the repair within 5 calendar days of detection.

6. Delay of repair of equipment for which leaks have been detected is allowed if repair within 15 days is technically infeasible without a process unit shutdown or as specified in paragraphs h.6.i. through v. of this condition. Repair of this equipment shall 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.

   i. Delay of repair of equipment is allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

   ii. Delay of repair for valves and connectors is allowed if the conditions in paragraphs h.6.ii.a. and b. of this section are met.

      a. The permittee must demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

      b. When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph f. of this condition.

   iii. Delay of repair for pumps is allowed if the conditions in paragraphs h.6.iii.a. and b. of this condition are met.

      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.

   iv. If delay of repair is required to repack or replace the valve, the permittee may use delay of repair. Delay of repair beyond a process unit shutdown is 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.

   v. 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 bimonthly monitoring results show no leak remains.

i. **Initial compliance.** The permittee must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5410b(h).

j. **Continuous compliance.** The permittee must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5415b(j).

k. **Reporting.** The permittee must perform the reporting requirements as specified in 40 CFR §§60.5420b(b)(1) and (11) through (13), as applicable, and 40 CFR §60.5422b.

l. **Recordkeeping.** The permittee must perform the recordkeeping requirements as specified in 40 CFR §§60.5420b(c)(8) and (10) through (13), as applicable, and 40 CFR §60.5421b.

[45CSR16; 40 CFR §§60.5400b(a) to (c), (d), (d)(1), (d)(3), and (e) to (l)]

14.1.4. This condition provides alternative standards for process unit equipment affected facilities located at an onshore natural gas processing plant. The permittee may choose to comply with the standards in this condition instead of the requirements in 40 CFR §60.5400b. For purposes of the alternative standards provided in this condition, the permittee must comply with the requirements of paragraphs a. through m. of this condition to reduce methane and VOC emissions from equipment leaks, except as provided in 40 CFR §60.5402b.

a. **General standards.** The permittee must comply with the requirements in paragraph b. of this condition for each pump in light liquid service. The permittee must comply with the requirements of paragraph c. of this condition for each pressure relief device in gas/vapor service. The permittee must comply with the requirements in paragraph d. of this condition for each open-ended valve or line. The permittee must comply with the requirements in paragraph e. of this condition for each closed vent system and control device used to comply with the equipment leak provisions in this condition. The permittee must comply with paragraph f. of this condition for each valve in gas/vapor or light liquid service. The permittee must comply with paragraph g. of this condition for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. The permittee must comply with paragraph h. of this condition for each connector in gas/vapor and light liquid service. The permittee must make repairs as specified in paragraph i. of this condition. The permittee must demonstrate initial compliance with the standards as specified in paragraph j. of this condition. The permittee must demonstrate continuous compliance with the standards as specified in paragraph k. of this condition. The permittee must perform the reporting requirements as specified in paragraph l. of this condition. The permittee must perform the recordkeeping requirements as required in paragraph m. of this condition.

1. The permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in 40 CFR 60, Subpart OOOOb according to the requirements of 40 CFR §60.5399b.

2. Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of Appendix A-6 to 40 CFR 60. Alternatively, if the piece of equipment is in wet gas service, the permittee may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see 40 CFR §60.17).

b. **Pumps in light liquid service.** The permittee must monitor each pump in light liquid service monthly to detect leaks by the methods specified in 40 CFR §60.5403b, except as provided in paragraphs b.2.

through 6. of this section. A leak is defined as an instrument reading of 2,000 ppmv or greater. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs b.2. through 6. of this condition.

1. In addition to the requirements in paragraph b. of this condition, the permittee must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal. If there are indications of liquids dripping from the pump seal, the permittee must follow the procedure specified in either paragraph b.1.i. or ii. of this condition.

    i. Monitor the pump within 5 days using the methods specified in 40 CFR §60.5403b. A leak is defined as an instrument reading of 2,000 ppmv or greater.

    ii. Designate the visual indications of liquids dripping as a leak, and repair the leak as specified in paragraph i. of this condition.

2. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements in paragraph b. of this condition, provided the requirements specified in paragraphs b.2.i. through v. are met.

    i. Each dual mechanical seal system meets the requirements of paragraph b.2.i.a., b., or c. of this condition.

        a. Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

        b. Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of paragraph e. of this condition; or

        c. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

    ii. The barrier fluid system is in heavy liquid service or does not have the potential to emit methane or VOC.

    iii. Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

    iv. Each pump is checked according to the requirements in paragraph b.1. of this condition.

    v. Each sensor meets the requirements in paragraphs b.2.v.a. through c. of this condition.

        a. Each sensor as described in paragraph b.2.iii. of this condition is checked daily or is equipped with an audible alarm.

        b. The permittee determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

c. If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph b.2.v.b. of this condition, a leak is detected.

3. Any pump that is designated, as described in 40 CFR §60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of paragraphs b. introductory text, b.1., and b.2. of this condition if the pump:

i. Has no externally actuated shaft penetrating the pump housing;

ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background as measured by the methods specified in 40 CFR §60.5403b; and

iii. Is tested for compliance with paragraph b.3.ii. of this condition initially upon designation, annually, and at other times requested by the Administrator.

4. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph e. of this condition, it is exempt from paragraphs b., b.1. through 3. of this condition, and the repair requirements of paragraph i. of this condition.

5. Any pump that is designated, as described in 40 CFR §60.5421b(b)(13), as an unsafe-to-monitor pump is exempt from the inspection and monitoring requirements of paragraphs b. introductory text, b.1., and b.2.iv. and v. of this section if the conditions in paragraphs b.5.i. and ii. of this section are met.

i. The permittee demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph b. of this section; and

ii. The permittee has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and the permittee repairs the equipment according to the procedures in paragraph i. of this condition if a leak is detected.

6. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraphs b.1. and b.2.iv. of this condition, and the daily requirements of paragraph b.2.v. of this condition, provided that each pump is visually inspected as often as practicable and at least monthly.

c. **Pressure relief devices in gas/vapor service.** The permittee must monitor each pressure relief device quarterly using the methods specified in 40 CFR §60.5403b. A leak is defined as an instrument reading of 500 ppmv or greater above background.

1. In addition to the requirements in paragraph c. introductory text of this condition, after each pressure release, the permittee must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks. A leak is detected if an instrument reading of 500 ppmv or greater is provided using the methods specified in 40 CFR §60.5403b(b).

2. Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph e. of this condition is exempt from the requirements of paragraph c. introductory text and c.1. of this condition.

3. Pressure relief devices equipped with a rupture disk are exempt from the requirements of paragraph c.1. of this condition provided the permittee installs a new rupture disk upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in paragraph i.6. of this condition.

d. **Open-ended valves or lines.** Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs d.4. and 5. of this condition. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

1. If evidence of a leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph i. of this condition. A leak is defined as an instrument reading of 500 ppmv or greater if Method 21 of Appendix A-7 to 40 CFR 60 is used.

2. Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

3. 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 shall remain closed at all other times.

4. 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 the requirements of paragraphs d. introductory text, and d.1. through 3. of this condition.

5. 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 as specified in paragraphs d. introductory text, d.2., and 3. of this condition are exempt from the requirements of this section.

e. **Closed vent systems and control devices.** Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in 40 CFR §§60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in 40 CFR §§60.5412b, 60.5415b(f), and 60.5417b.

f. **Valves in gas/vapor and light liquid service.** The permittee must monitor each valve in gas/vapor and in light liquid service quarterly to detect leaks by the methods specified in 40 CFR §60.5403b, except as provided in paragraphs f.3. through 5. of this condition.

1. A valve that begins operation in gas/vapor service or in light liquid service after the initial startup date for the process unit must be monitored for the first time within 90 days after the end of its startup period to ensure proper installation, except for a valve that replaces a leaking valve and except as provided in paragraphs f.3. through 5. of this condition.

2. An instrument reading of 500 ppmv or greater is a leak. The permittee must repair each leaking valve according to the requirements in paragraph i. of this condition.

3. Any valve that is designated, as described in 40 CFR §60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the monitoring requirements of paragraph f. of this condition if the valve:

   i. Has no externally actuating mechanism in contact with the process fluid;

   ii. Is operated with emissions less than 500 ppmv above background as determined by the methods specified in 40 CFR §60.5403b; and

   iii. Is tested for compliance with paragraph f.3.ii. of this condition initially upon designation, annually, and at other times requested by the Administrator.

4. Any valve that is designated, as described in 40 CFR §60.5421b(b)(13), as an unsafe-to-monitor valve is exempt from the monitoring requirements of paragraph f. of this condition if the requirements in paragraphs f.4.i. and ii. of this condition are met.

   i. The permittee demonstrates that the valve is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph f. of this condition; and

   ii. The permittee has a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and the permittee repairs the equipment according to the procedures in paragraph i. of this condition if a leak is detected.

5. Any valve that is designated, as described in 40 CFR §60.5421b(b)(14), as a difficult-to-monitor valve is exempt from the monitoring requirements of paragraph f. of this condition if the requirements in paragraph f.5.i. through iii. of this condition are met.

   i. The permittee demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

   ii. The process unit within which the valve is located has less than 3.0 percent of its total number of valves designated as difficult-to-monitor.

   iii. The permittee has a written plan that requires monitoring of the at least once per calendar year.

g. **Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.** If evidence of a potential leak is found at any time by AVO, or any other detection method, the permittee must comply with either paragraph g.1. or 2. of this condition.

   1. The permittee must monitor the equipment within 5 calendar days by the method specified in 40 CFR §60.5403b and repair any leaks detected according to paragraph i. of this condition. An instrument reading of 10,000 ppmv or greater is defined as a leak.

2. The permittee must designate the AVO, or other indication of a leak as a leak and repair the leak according to paragraph i. of this condition.

h. **Connectors in gas/vapor service and in light liquid service.** The permittee must initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the permittee is required to monitor only those connectors involved in the process change.

1. The permittee must monitor all connectors in gas/vapor service and all connectors in light liquid service annually, except as provided in 40 CFR §60.5399b, paragraph e. of this condition or paragraph h.2. of this condition. If an instrument reading greater than or equal to 500 ppmv is measured, a leak is detected.

2. Any connector that is designated, as described in 40 CFR §60.5421b(b)(13), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs h. introductory text and h.1. of this condition if the requirements of paragraphs h.2.i. and ii. of this condition are met.

i. The permittee demonstrates the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs h. introductory text and h.1. of this condition; and

ii. 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 the permittee repairs the equipment according to the procedures in paragraph i. of this condition if a leak is detected.

3. Inaccessible, ceramic, or ceramic-line connectors.

i. Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs h. and h.1. of this condition, from the leak repair requirements of paragraph i. of this condition, and from the recordkeeping and reporting requirements of 40 CFR §§60.5421b and 60.5422b. An inaccessible connector is one that meets any of the specifications in paragraphs h.3.i.a. through f. of this condition, as applicable.

a. Buried.

b. Insulated in a manner that prevents access to the connector by a monitor probe.

c. Obstructed by equipment or piping that prevents access to the connector by a monitor probe.

d. Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground.

e. Inaccessible because it would require elevating monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold.

f. Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment.

ii. If any inaccessible, ceramic, or ceramic-lined connector is observed by AVO or other means to be leaking, the indications of a leak to the atmosphere by AVO or other means must be eliminated as soon as practicable.

4. Connectors which are part of an instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph h.3. of this condition, are not subject to the recordkeeping requirements of 40 CFR §60.5421b(b)(1).

i. **Repair requirements.** When a leak is detected, comply with the requirements of paragraphs i.1. through 5. of this condition, except as provided in paragraph i.6. of this condition.

1. A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on the equipment may be removed after it has been repaired.

2. A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected.

i. First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs i.2.i.a. and b. of this condition, where practicable.

a. Tightening the packing gland nuts.

b. Ensuring that the seal flush is operating at design pressure and temperature.

ii. For each valve where a leak is detected, the permittee must comply with paragraph i.2.ii.a., b., or c. of this condition, unless the permittee meets the requirements of paragraph i.2.ii.d. of this condition.

a. Repack the existing valve with a low-e packing.

b. Replace the existing valve with a low-e valve; or

c. Perform a drill and tap repair with a low-e injectable packing.

d. An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in

determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

3. Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraph i.4., 5., or 6. of this condition.

4. If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, the permittee must make the repair within 5 calendar days of detection.

5. If the repair for AVO or other indication of a leak for open-ended lines or valves; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, the permittee must make the repair within 5 calendar days of detection.

6. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 calendar days is technically infeasible without a process unit shutdown or as specified in paragraphs i.6.i. through v. of this condition. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 calendar days after startup of the process unit.

   i. Delay of repair of equipment will be allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

   ii. Delay of repair for valves and connectors will be allowed if the conditions in paragraphs i.6.ii.a. and b. are met.

      a. The permittee demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

      b. When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph e. of this condition.

   iii. Delay of repair for pumps will be allowed if the conditions in paragraphs i.6.iii.a. and b. are met.

      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.

   iv. If delay of repair is required to repack or replace the valve, the permittee may use delay of repair. 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.

v. 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 results show no leak remains.

j. **Initial compliance.** The permittee must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5410b(h).

k. **Continuous compliance.** The permittee must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5415b(j).

l. **Reporting.** The permittee must perform the reporting requirements as specified in 40 CFR §§60.5420b(b)(1) and (11) through (13), as applicable, and 40 CFR §60.5422b.

m. **Recordkeeping.** The permittee must perform the recordkeeping requirements as specified in 40 CFR §§60.5420b(c)(8) and (10) through (13), as applicable, and 40 CFR §60.5421b.

[45CSR16; 40 CFR §§60.5401b(a) to (c), (c)(1), (c)(4), (c)(5), and (d) to (m)]

Compressors

14.1.5. The permittee shall maintain on-site and available upon request an updated list of all reciprocating compressors and the applicability of each to 40 CFR 60 Subparts OOOO, OOOOa, and OOOOb. For each compressor, the permittee shall comply with all applicable requirements given under 40 CFR 60 Subpart OOOO, OOOOa, or OOOOb, whichever is applicable dependent on the applicability determined under this requirement.
[45CSR13, R13-2896, Condition 17.1.2.; 45CSR§30-5.1.c.]

14.1.6. **Subpart OOOO Standards.** The permittee must comply with the standards in paragraphs a. through d. of this condition for each reciprocating compressor affected facility.

a. The permittee must replace the reciprocating compressor rod packing according to either paragraph a.1. or 2. of this condition or the permittee must comply with paragraph a.3. of this condition.

1. Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of the reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

2. Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

3. Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of 40 CFR §60.5411(a).

b. The permittee must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5410.

c. The permittee must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5415.

d. The permittee must perform the required notification, recordkeeping, and reporting as required by 40 CFR §60.5420.

[45CSR16; 40 CFR §60.5385]

14.1.7. **Closed vent system requirements for reciprocating compressors under Subpart OOOO.**

a. Closed vent system requirements for reciprocating compressors complying with Condition 14.1.6.a.3.

1. The permittee must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the reciprocating compressor rod packing emissions collection system or the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in 40 CFR §§60.5412(a) through (c).

2. The permittee must design and operate the closed vent system with no detectable emissions as demonstrated by 40 CFR §60.5416(b).

3. The permittee must meet the requirements specified in paragraphs a.3.i. and ii. of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

i. Except as provided in paragraph a.3.ii. of this section, the permittee must comply with either paragraph a.3.i.a. or b. of this section for each bypass device.

a. The permittee must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in 40 CFR §60.5416(a)(4) and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. The permittee must maintain records of each time the alarm is activated according to 40 CFR §60.5420(c)(8).

b. The permittee must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

ii. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph a.3.i. of this section.

[45CSR16; 40 CFR §§60.5411 and 60.5411(a)]

14.1.8. **Subpart OOOOa Standards.** The permittee must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs a. through d. of this condition for each reciprocating compressor affected facility.

a. The permittee must replace the reciprocating compressor rod packing according to either paragraph a.1. or 2. of this condition, or the permittee must comply with paragraph a.3. of this condition.

1. On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of the reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

2. Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

3. Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of 40 CFR §§60.5411a(a) and (d).

b. The permittee must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5410a(c).

c. The permittee must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5415a(c).

d. The permittee must perform the reporting as required by 40 CFR §§60.5420a(b)(1) and (4) and the recordkeeping as required by 40 CFR §§60.5420a(c)(3), (6) through (8), and (17), as applicable.

[45CSR16; 40 CFR §60.5385a]

14.1.9. **Closed vent system requirements for reciprocating compressors under Subpart OOOOa.** The permittee must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for the reciprocating compressors complying with Condition 14.1.8.a.3.

a. Closed vent system requirements for reciprocating compressors.

1. The permittee must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process.

2. The permittee must design and operate the closed vent system with no detectable emissions as demonstrated by 40 CFR §60.5416a(b).

3. The permittee must meet the requirements specified in paragraphs a.3.i. and ii. of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

i. Except as provided in paragraph a.3.ii. of this section, the permittee must comply with either paragraph a.3.i.a. or b. of this section for each bypass device.

a. The permittee must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in 40 CFR §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. The permittee must maintain records of each time the alarm is activated according to 40 CFR §60.5420a(c)(8).

b. The permittee must secure the bypass device valve installed at the inlet to the bypass device in a non-diverting position using a car-seal or a lock-and-key type configuration.

ii. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph a.3.i. of this section.

b. Closed vent systems requirements for reciprocating compressors using a control device or routing emissions to a process.

1. The permittee must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected facility are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility, and have it certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (d)(1)(i) and (ii) of 40 CFR §60.5411a.

i. The permittee must provide the following certification signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of Subpart OOOOa of 40 CFR 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

ii. The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph d.1.i. of this section.

[45CSR16; 40 CFR §§60.5411a, 60.5411a(a), and 60.5411a(d)]

14.1.10. **Subpart OOOOb Standards.** Each reciprocating compressor affected facility must comply with the GHG and VOC standards, using volumetric flow rate as a surrogate, in paragraphs a. through c. of this condition, or the GHG and VOC standards in paragraph d. of this condition. The permittee must also comply with the requirements in paragraphs e. through g. of this condition.

a. The volumetric flow rate of each cylinder, measured in accordance paragraph b. or c. of this condition, must not exceed 2 scfm per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. The permittee must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs a.1. and 2. of this condition and determine the volumetric flow rate per cylinder in accordance with paragraph b. or c. of this condition. If the

volumetric flow rate, measured in accordance with paragraph b. or c. of this condition, for a cylinder exceeds 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), the rod packing or packings must be repaired or replaced as provided in paragraph a.3. of this condition.

1. The permittee must conduct the first volumetric flow rate measurements from the reciprocating compressor rod packing vent on or before 8,760 hours of operation after the last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever date is later.

2. The permittee must conduct subsequent volumetric flow rate measurements from the reciprocating compressor rod packing vent on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the applicable volumetric flow rate of 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), or on or before 8,760 hours of operation after last rod packing replacement, whichever date is later.

3. The rod packing must be repaired or replaced within 90 calendar days after the date of the volumetric emissions measurement that exceeded 2 scfm per cylinder. The permittee must conduct follow-up volumetric flow rate measurements from compressor vents using the methods specified in paragraphs b. or c. of this condition within 15 days after the repair (or rod packing replacement) to document that the rate has been reduced to less than 2 scfm per cylinder. Delay of repair will be allowed if the conditions in paragraphs a.3.i. or ii. of this condition are met.

    i. If the repair (or rod packing replacement) is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair (or rod packing replacement) must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per cylinder, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

    ii. If the repair requires replacement of the rod packing or a part, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph a.3.ii.a. of this section, the repair must be completed in accordance with paragraph a.3.ii.b. of this section and documented in accordance with 40 CFR §§60.5420b(c)(5)(viii) through (x).

        a. Rod packing or part supplies had been sufficiently stocked but are depleted at the time of the required repair.

        b. The required rod packing or part replacement must be ordered no later than 10 calendar days after the reciprocating compressor is added to the delay of repair list due to parts unavailability. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement rod packing or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph a.3.i. of this condition.

b. The permittee must determine the volumetric flow rate per cylinder from the reciprocating compressor as specified in paragraph b.1. or 2. of this condition.

1. For reciprocating compressor rod packing equipped with an open-ended vent line on compressors in operating or standby pressurized mode, determine the volumetric flow rate of the rod packing using one of the methods specified in paragraphs b.1.i. through iii. of this condition.

i. Determine the volumetric flow rate at standard conditions from the open-ended vent line using a high-volume sampler according to methods set forth in 40 CFR §60.5386b(c).

ii. Determine the volumetric flow rate at standard conditions from the open-ended vent line using a temporary or permanent meter, according to methods set forth in 40 CFR §60.5386b(b).

iii. Any of the methods set forth in 40 CFR §60.5386b(a) to screen for leaks and emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected according to any of the methods in 40 CFR §60.5386b(a). If emissions are detected using the methods set forth in 40 CFR §60.5386b(a), then the permittee must use one of the methods specified in paragraphs b.1.i. and ii. of this condition to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in 40 CFR §60.5386b(a), then the permittee may assume that the volumetric flow rate is zero.

2. For reciprocating compressor rod packing not equipped with an open-ended vent line on compressors in operating or standby pressurized mode, the permittee must determine the volumetric flow rate of the rod packing using the methods specified in paragraphs b.2.i. and ii. of this condition.

i. The permittee must use the methods described in 40 CFR §60.5386b(a) to conduct leak detection of emissions from the rod packing case into an open distance piece, or, for compressors with a closed distance piece, the permittee must conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

ii. The permittee must measure emissions found in paragraph b.2.i. of this condition using a meter or high-volume sampler according to methods set forth in 40 CFR §60.5386b(b) or (c).

c. For conducting measurements on manifolded groups of reciprocating compressor affected facilities, the permittee must determine the volumetric flow rate from reciprocating compressor rod packing vent as specified in paragraphs c.1. and 2. of this condition.

1. Measure at a single point in the manifold downstream of all compressor vent inputs and, if practical, prior to comingling with other non-compressor emission sources.

2. Determine the volumetric flow rate per cylinder at standard conditions from the common stack using one of the methods specified in paragraphs c.2.i. through iv. of this condition.

i. A temporary or permanent flow meter according to the methods set forth in 40 CFR §60.5386b(b).

ii. A high-volume sampler according to the methods set forth in 40 CFR §60.5386b(c).

iii. An alternative method, as set forth in 40 CFR §60.5386b(d).

iv. Any of the methods set forth in 40 CFR §60.5386b(a) to screen for emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected when using any of the methods in 40 CFR §60.5386b(a). If emissions are detected using the methods set forth in 40 CFR §60.5386b(a), then the permittee must use one of the methods specified in paragraphs c.2.i. through iii. of this condition to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in 40 CFR §60.5386b(a), then the permittee may assume that the volumetric flow rate is zero.

d. As an alternative to complying with the GHG and VOC standards in paragraphs a. through c. of this condition, owners and operators can meet the requirements specified in paragraph d.1., 2., or 3. of this condition.

1. Collect the methane and VOC emissions from the reciprocating compressor rod packing using a rod packing emissions collection system that is operated to route the rod packing emissions to a process. In order to comply with this option, the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c).

2. Reduce methane and VOC emissions from each rod packing emissions collection system by using a control device that reduces methane and VOC emissions by 95.0 percent. In order to comply with this option, the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in 40 CFR §60.5412b.

3. As an alternative to conducting the required volumetric flow rate measurements under paragraph a. of this condition, an owner or operator can choose to comply by replacing the rod packing on or before 8,760 hours of operation after startup, on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever date is later.

e. The permittee must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5410b(e).

f. The permittee must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5415b(g).

g. The permittee must perform the reporting requirements as specified in 40 CFR §§60.5420b(b)(1), (6), and (11) through (13), as applicable; and the recordkeeping requirements as specified in 40 CFR §§60.5420b(c)(5) and (8) through (13), as applicable.

[45CSR16; 40 CFR §60.5385b]

14.1.11. **Closed vent system requirements for reciprocating compressors and process unit equipment under Subpart OOOOb.** For each cover or closed vent system at the reciprocating compressor and process unit equipment affected facilities, the permittee must comply with the applicable requirements of paragraphs a. through c. of this condition.

a. *Closed vent system requirements.*

1. **Reciprocating compressor rod packing.** The permittee must design the closed vent system to capture and route all gases, vapors, and fumes to a process.

2. **Process Unit Equipment.** The permittee must design the closed vent system to capture and route all gases, vapors, and fumes to a process or a control device that meets the requirements specified in 40 CFR §§60.5412b(a) through (d).

3. The permittee must design and operate the closed vent system with no identifiable emissions as demonstrated by 40 CFR §§60.5416b(a) and (b).

4. **Bypass devices.** The permittee must meet the requirements specified in paragraphs a.4.i. and ii. of this condition if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or being routed to a process.

i. Except as provided in paragraph a.4.ii. of this condition, the permittee must comply with either paragraph a.4.i.a. or b. of this condition for each bypass device.

a. The permittee must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device. The flow indicator must be capable of taking periodic readings as specified in 40 CFR §60.5416b(a)(4)(i) and sound an alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process, and sent to the atmosphere. The permittee must maintain records of each time the alarm is activated according to 40 CFR §60.5420b(c)(10).

b. The permittee must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

ii. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of 40 CFR §60.5411b(a)(4)(i).

b. *Cover requirements for reciprocating compressors.*

1. The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the reciprocating compressor rod packing emissions collection system.

2. Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

i. To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

ii. To inspect or sample the material in the unit;

iii. To inspect, maintain, repair, or replace equipment located inside the unit; or

iv. To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph a. of this condition to a control device or to a process.

3. The permittee must design and operate the cover with no identifiable emissions as demonstrated by 40 CFR §§60.5416b(a) and (b), except when operated as provided in paragraphs b.2.i. through iv. of this condition.

c. *Design requirements.*

1. The permittee must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all gases, vapors, and fumes from the affected facility are routed to the control device or process and that the control device or process is of sufficient design and capacity to accommodate all emissions from the affected facility. The assessment must be certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs c.1.i. and ii. of this condition.

i. The permittee must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of 40 CFR 60, Subpart OOOOb. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

ii. The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph c.1.i. of this condition.

[45CSR16; 40 CFR §§60.5411b(a), (b)(1), (b)(2), (b)(4), and (c)]

14.1.12. The permittee is deemed to be in compliance with 40 CFR 60 Subpart OOOO if they are in compliance with all applicable provisions of 40 CFR 60, Subpart OOOOa.
[45CSR16; 40 CFR §60.5370(d)]

14.1.13. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall 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 Administrator which may include but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR §60.8(c) do not apply to 40 CFR Subpart OOOOa or Subpart OOOOb.
[45CSR16; 40 CFR §60.5370(b); 40 CFR §60.5370a(b); 40 CFR §60.5370b(b)]

14.2. Monitoring Requirements

FUG AREAS 1 through 4 (40 CFR 60, Subpart OOOOa)

14.2.1. Exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants:

a. The permittee may comply with the following exceptions to the provisions of 40 CFR §§60.5400a(a) and (b).

b. 1. Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in 40 CFR §60.485a(b) except as provided in 40 CFR §60.5400a(c) and in 40 CFR §60.5401a(b)(4), and 40 CFR §§60.482-4a(a) through (c) of 40 CFR 60, Subpart VVa.

2. If an instrument reading of 500 ppm or greater is measured, a leak is detected.

3. Leak Repair:

i. When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in 40 CFR §60.482-9a.

ii. A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

c. Sampling connection systems are exempt from the requirements of 40 CFR §60.482-5a.

d. An owner or operator may use the following provisions instead of 40 CFR §60.485a(e):

1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in 40 CFR §60.17).

2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in 40 CFR §60.17).

e. An owner or operator may use the following provisions instead of 40 CFR §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of Appendix A-7 of 40 CFR 60, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in 40 CFR §60.486a(e)(8). For each scale, divide the arithmetic difference of the most recent calibration and the post-test calibration response by the corresponding calibration gas value, and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the most recent calibration response, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the most recent calibration response, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[45CSR16; 40 CFR §§60.5401a(a), (b)(1) to (3), (c), (f), and (g)]

FUG AREA 5 through 7 (40 CFR 60, Subpart OOOOb)

14.2.2. Exceptions to the GHG and VOC standards for process unit equipment affected facilities:

a. The permittee may comply with the following exceptions to the provisions of 40 CFR §§60.5400b(a) and 60.5401b(a), as applicable.

b. The permittee may use the following provisions instead of 40 CFR §60.5403b(d):

1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM D86-96 (incorporated by reference, see 40 CFR §60.17).

2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM D86-96 (incorporated by reference, see 40 CFR §60.17).

c. Equipment that is in vacuum service, except connectors in gas/vapor and light liquid service, is excluded from the requirements of 40 CFR §§60.5400b(b) through (g), if it is identified as required in 40 CFR §60.5421b(b)(15). Equipment that is in vacuum service is excluded from the requirements of 40 CFR §§60.5401b(b) through (g) if it is identified as required in 40 CFR §60.5421b(b)(15).

d. Equipment that is designated as having the potential to emit methane or VOC less than 300 hr/yr is excluded from the requirements of 40 CFR §§60.5400b(b) through (g) and 40 CFR §§60.5401b(b) through (h), if it is identified as required in 40 CFR §60.5421b(b)(16) and it meets any of the conditions specified in paragraphs d.1. through 3. of this condition.

1. The equipment has the potential to emit methane or VOC only during startup and shutdown.

2. The equipment has the potential to emit methane or VOC only during process malfunctions or other emergencies.

3. The equipment is backup equipment that has the potential to emit methane or VOC only when the primary equipment is out of service.

[45CSR16; 40 CFR §§60.5402b(a) and (d) to (f)]

14.2.3. **Initial compliance demonstration for process unit equipment affected facilities under 40 CFR 60, Subpart OOOOb.** To achieve initial compliance with the GHG and VOC standards for process unit equipment affected facilities as required by 40 CFR §60.5400b, the permittee must comply with paragraphs a. through d. and k. through o. of this condition, unless the permittee meets and complies with the exception in 40 CFR §§60.5402b(b), (e), or (f) or meets the exemption in 40 CFR §60.5402b(c). If the permittee complies with the GHG and VOC standards for process unit equipment affected facilities using the alternative standards in 40 CFR §60.5401b, the permittee must comply with paragraphs e. through o. of this condition, unless the permittee meets the exemption in 40 CFR §60.5402b(b) or (c) or the exception in 40 CFR §60.5402b(e) or (f).

a. The permittee must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service and connector in gas/vapor or light liquid service as required by 40 CFR §60.5400b(b).

b. The permittee must conduct monitoring as required by 40 CFR §60.5400b(c) for each pump in light liquid service.

c. The permittee must conduct monitoring as required by 40 CFR §60.5400b(d) for each pressure relief device in gas/vapor service.

d. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5400b(e).

e. The permittee must conduct monitoring for each pump in light liquid service as required by 40 CFR §60.5401b(b).

f. The permittee must conduct monitoring for each pressure relief device in gas/vapor service as required by 40 CFR §60.5401b(c).

g. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5401b(d).

h. The permittee must conduct monitoring for each valve in gas/vapor or light liquid service as required by 40 CFR §60.5401b(f).

i. The permittee must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by 40 CFR §60.5401b(g).

j. The permittee must conduct monitoring for each connector in gas/vapor or light liquid service as required by 40 CFR §60.5401b(h).

k. For each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or a control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or a control device, the permittee must meet the requirements of paragraph k.1. through 6. of this condition.

    1. Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of 40 CFR §60.5413b or route to a process.

    2. Install a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c) to capture all emissions from each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir, each pump which captures and transports leakage from the seal or seals, or each pressure relief device which captures and transports leakage through the pressure relief device and route all emissions to a process or to a control device that meets the conditions specified in 40 CFR §60.5412b.

    3. If routing to a control device, conduct an initial performance test as required in 40 CFR §60.5413b within 180 days after initial startup, or install a control device tested under 40 CFR §60.5413b(d)

which meets the criteria in 40 CFR §§60.5413b(d)(11) and (e), and the permittee must comply with the continuous compliance requirements of 40 CFR §60.5415b(f).

4. Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in 40 CFR §§60.5416b(a) and (b).

5. Install and operate the continuous parameter monitoring systems in accordance with 40 CFR §§60.5417b(a) through (i), as applicable.

6. Maintain the records as required by 40 CFR §§60.5420b(c)(8) and (c)(10) through (13), as applicable and submit the reports as required by 40 CFR §§60.5420b(b)(11) through (13), as applicable.

l. The permittee must tag and repair each identified leak as required in 40 CFR §60.5400b(h) or §60.5401b(i), as applicable.

m. The permittee must submit the notice required by 40 CFR §60.5420b(a)(1).

n. The permittee must submit the initial semiannual report and subsequent semiannual report as required by 40 CFR §60.5422b.

o. The permittee must maintain the records specified by 40 CFR §60.5421b.

[45CSR16; 40 CFR §60.5410b(h)]

14.2.4. **Continuous compliance demonstration for process unit equipment affected facilities under 40 CFR 60, Subpart OOOOb.** For each process unit equipment affected facility, the permittee must demonstrate continuous compliance with the requirements of 40 CFR §60.5400b according to paragraphs a. through d. and k. through o. of this condition, unless the permittee meets and complies with the exception in 40 CFR §60.5402b(b), (e), or (f) or meets the exemption in 40 CFR §60.5402b(c). Alternatively, if the permittee complies with the GHG and VOC standards for process unit affected facilities using the standards in 40 CFR §60.5401b, the permittee must comply with paragraphs e. through o. of this condition, unless the permittee meets the exemption in 40 CFR §60.5402b(b) or (c) or the exception in 40 CFR §§60.5402b(e) and (f).

a. The permittee must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor and light liquid service and connector in gas/vapor and light liquid service as required by 40 CFR §60.5400b(b).

b. The permittee must conduct monitoring as required by 40 CFR §60.5400b(c) for each pump in light liquid service.

c. The permittee must conduct monitoring as required by 40 CFR §60.5400b(d) for each pressure relief device in gas/vapor service.

d. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5400b(e).

e. The permittee must conduct monitoring for each pump in light liquid service as required by 40 CFR §60.5401b(b).

f. The permittee must conduct monitoring for each pressure relief device in gas/vapor service as required by 40 CFR §60.5401b(c).

g. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5401b(d).

h. The permittee must conduct monitoring for each valve in gas/vapor or light liquid service as required by 40 CFR §60.5401b(f).

i. The permittee must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by 40 CFR §60.5401b(g).

j. The permittee must conduct monitoring for each connector in gas/vapor or light liquid service as required by 40 CFR §60.5401b(h).

k. The permittee must collect emissions and meet the closed vent system requirements as required by 40 CFR §60.5416b for each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or control device.

l. The permittee must comply with the requirements specified in 40 CFR §60.5415b(f).

m. The permittee must tag and repair each identified leak as required in 40 CFR §60.5400(h) or §60.5401b(i), as applicable.

n. The permittee must submit semiannual reports as required by 40 CFR §60.5422b and the annual reports in 40 CFR §§60.5420b(b)(11)(i) through (iv), as applicable.

o. The permittee must maintain the records specified by 40 CFR §§60.5420b(c)(8), (c)(10), and (c)(12) as applicable and 40 CFR §60.5421b.

[45CSR16; 40 CFR §60.5415b(j)]

Compressors

14.2.5. **Initial compliance demonstration for 40 CFR 60, Subpart OOOO.** To achieve initial compliance with the standards for each reciprocating compressor affected facility the permittee must comply with paragraphs a. through d. of this condition.

a. If complying with 40 CFR §60.5385(a)(1) or (2), during the initial compliance period, the permittee must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

b. If complying with 40 CFR §60.5385(a)(3), the permittee must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of 40 CFR §60.5411(a).

c. The permittee must submit the initial annual report for the reciprocating compressor as required in 40 CFR §60.5420(b).

d. The permittee must maintain the records as specified in 40 CFR §60.5420(c)(3) for each reciprocating compressor affected facility.

[45CSR16; 40 CFR §60.5410(c)]

14.2.6. **Continuous compliance demonstration for 40 CFR 60, Subpart OOOO.** For each reciprocating compressor affected facility complying with 40 CFR §60.5385(a)(1) or (2), the permittee must demonstrate continuous compliance according to paragraphs a. through c. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385(a)(3), the permittee must demonstrate continuous compliance according to paragraph d. of this condition.

a. The permittee must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

b. The permittee must submit the annual report as required in 40 CFR §60.5420(b) and maintain records as required in 40 CFR §60.5420(c)(3).

c. The permittee must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

d. The permittee must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in 40 CFR §§60.5416(a) and (b).

[45CSR16; 40 CFR §60.5415(c)]

14.2.7. **Initial compliance demonstration for 40 CFR 60, Subpart OOOOa.** To achieve initial compliance with the standards for each reciprocating compressor affected facility the permittee must comply with paragraphs a. through d. of this condition.

a. If complying with 40 CFR §60.5385a(a)(1) or (2), during the initial compliance period, the permittee must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

b. If complying with 40 CFR §60.5385a(a)(3), the permittee must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of 40 CFR §§60.5411a(a) and (d).

c. The permittee must submit the initial annual report for the reciprocating compressor as required in 40 CFR §§60.5420a(b)(1) and (4).

d. The permittee must maintain the records as specified in 40 CFR §60.5420a(c)(3) for each reciprocating compressor affected facility.

[45CSR16; 40 CFR §60.5410a(c)]

14.2.8. **Continuous compliance demonstration for 40 CFR 60, Subpart OOOOa.** For each reciprocating compressor affected facility complying with 40 CFR §60.5385a(a)(1) or (2), the permittee must demonstrate continuous compliance according to paragraphs a. through c. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385a(a)(3), the permittee must demonstrate continuous compliance according to paragraph c.4. of this condition.

a. The permittee must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

b. The permittee must submit the annual reports as required in 40 CFR §§60.5420a(b)(1) and (4) and maintain records as required in 40 CFR §60.5420a(c)(3).

c. The permittee must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

d. The permittee must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in 40 CFR §§60.5416a(a) and (b).

[45CSR16; 40 CFR §60.5415a(c)]

14.2.9. **Initial compliance demonstration for 40 CFR 60, Subpart OOOOb.** To demonstrate initial compliance with the GHG and VOC standards for each reciprocating compressor affected facility as required by 40 CFR §60.5385b, the permittee must comply with paragraphs a. through g. of this condition.

a. If the permittee complies with 40 CFR §60.5385b by maintaining volumetric flow rate at or below 2 scfm per cylinder (or a combined cylinder volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm) as required by 40 CFR §60.5385b(a), the permittee must maintain volumetric flow rate at or below 2 scfm and the permittee must conduct the initial annual volumetric flow rate measurement as required by 40 CFR §60.5385b(a)(1).

b. If the permittee complies with 40 CFR §60.5385b by collecting the methane and VOC emissions from the reciprocating compressor rod packing using a rod packing emissions collection system as required by 40 CFR §60.5385b(d)(1), the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b), route emissions to a process through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c), and the permittee must conduct the initial inspections required in 40 CFR §§60.5416b(a) and (b).

c. If the permittee complies with 40 CFR §60.5385b(d) by collecting the emissions from the rod packing emissions collection system by using a control device to reduce VOC and methane emissions by 95.0 percent as required by 40 CFR §60.5385b(d)(2), the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b), route emissions to a control device that meets the conditions specified in 40 CFR §60.5412b through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c) and the permittee must conduct the initial inspections required in 40 CFR §§60.5416b(a) and (b).

d. If the permittee complies with 40 CFR §60.5385b(d)(2), the permittee must conduct an initial performance test as required in 40 CFR §60.5413b within 180 days after initial startup, or install a control

device tested under 40 CFR §60.5413b(d) which meets the criteria in 40 CFR §§60.5413b(d)(11) and (e) and the permittee must comply with the continuous compliance requirements of 40 CFR §60.5415b(f).

e. If the permittee complies with 40 CFR §60.5385b(d)(2), the permittee must install and operate the continuous parameter monitoring systems in accordance with 40 CFR §§60.5417b(a) through (i), as applicable.

f. The permittee must submit the initial annual report for the reciprocating compressor as required in 40 CFR §§60.5420b(b)(1), (6), and (11) through (13), as applicable.

g. The permittee must maintain the records as specified in 40 CFR §§60.5420b(c)(5) and (8) through (13) as applicable.

[45CSR16; 40 CFR §60.5410b(e)]

14.2.10. **Continuous compliance demonstration for 40 CFR 60, Subpart OOOOb.** For each reciprocating compressor affected facility complying with 40 CFR §§60.5385b(a) through (c), the permittee must demonstrate continuous compliance according to paragraphs a., e., and f. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385b(d)(1) or (2), the permittee must demonstrate continuous compliance according to paragraphs b., e., and f. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385b(d)(3), the permittee must demonstrate continuous compliance according to paragraphs c. through f. of this condition.

a. The permittee must maintain the volumetric flow rate at or below 2 scfm per cylinder (or at or below the combined volumetric flow rate determined by multiplying the number of cylinders by 2 scfm), and the permittee must conduct the required volumetric flow rate measurement of the reciprocating compressor rod packing vents in accordance with 40 CFR §60.5385b(b) on or before 8,760 hours of operation after the last volumetric flow rate measurement which demonstrated compliance with the applicable volumetric flow rate.

b. The permittee must operate the rod packing emissions collection system to route emissions to a control device or to a process through a closed vent system and continuously comply with the cover and closed vent requirements of 40 CFR §60.5416b. If the permittee complies with 40 CFR §60.5385b(d) by use a control device, the permittee also must comply with the requirements in 40 CFR §60.5415b(f).

c. The permittee must continuously monitor the number of hours of operation for each reciprocating compressor affected facility since initial startup, since the previous flow rate measurement, or since the date of the most recent reciprocating compressor rod packing replacement, whichever date is latest.

d. The permittee must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 8,760 hours.

e. The permittee must submit the annual reports as required in 40 CFR §§60.5420b(b)(1), (6), and (11)(i) through (iv), as applicable.

f. The permittee must maintain records as required in 40 CFR §§60.5420b(c)(5), (8) through (10), and (12), as applicable.

[45CSR16; 40 CFR §60.5415b(g)]

14.2.11. **Additional continuous compliance requirements for reciprocating compressor and process unit equipment affected facilities under 40 CFR 60, Subpart OOOOb.** For each reciprocating compressor affected facility and each process unit equipment affected facility referenced to 40 CFR §60.5415b(f) from either 40 CFR §60.5415b(g)(2) or (j)(12), the permittee must also install monitoring systems as specified in 40 CFR §60.5417b, demonstrate continuous compliance according to 40 CFR §60.5415b(f)(1), maintain the records in 40 CFR §60.5415b(f)(2), and comply with the reporting requirements specified in 40 CFR §60.5415b(f)(3).
[45CSR16; 40 CFR §60.5415b(f)]

14.2.12. **Continuous monitoring requirements for control devices under Subpart OOOOb.** The permittee must meet the requirements of 40 CFR §60.5417b to demonstrate continuous compliance for each control device used to meet emission standards for reciprocating compressor and process unit equipment affected facilities.
[45CSR16; 40 CFR §60.5417b]

14.3. Testing Requirements

14.3.1. **Inspections for closed vent systems and covers installed on each reciprocating compressor affected facility under Subpart OOOO.** Except as provided in 40 CFR §§60.5416(b)(11) and (12), the permittee must inspect each closed vent system according to the procedures and schedule specified in paragraphs a. and b. of this condition, inspect each cover according to the procedures and schedule specified in paragraph c. of this condition, and inspect each bypass device according to the procedures of paragraph d. of this condition for reciprocating compressors complying with permit condition 14.1.6.a.3.

a. For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the permittee must meet the requirements specified in paragraphs a.1. and 2. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416(b) to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in 40 CFR §60.5416(b) to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

b. For closed vent system components other than those specified in paragraph a. of this condition, the permittee must meet the requirements of paragraphs b.1. through 3. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416(b) to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

2. Conduct annual inspections according to the test methods and procedures specified in 40 CFR §60.5416(b) to demonstrate that the components or connections operate with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

3. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

c. For each cover, the permittee must meet the following requirements:

1. Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, the permittee must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

2. The permittee must initially conduct the inspections specified in paragraph c.1. of this condition following the installation of the cover. Thereafter, the permittee must perform the inspection at least once every calendar year, except as provided in 40 CFR §§60.5416(b)(11) and (12). The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(7).

d. For each bypass device, except as provided for in 40 CFR §60.5411, the permittee must meet the following requirements:

1. Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

2. If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. The permittee must maintain records of the inspections according to 40 CFR §60.5420(c)(8).

[45CSR16; 40 CFR §60.5416(a)]

14.3.2. **No detectable emissions test methods and procedures under Subpart OOOO.** If the permittee is required to conduct an inspection of a closed vent system or cover at the reciprocating compressor affected facility as specified in 40 CFR §60.5416(a)(1), (2), or (3), the permittee must meet the requirements of 40 CFR §§60.5416(b)(1) through (13).
[45CSR16; 40 CFR §60.5416(b)]

14.3.3. **Inspections for closed vent systems and covers installed on each reciprocating compressor affected facility under Subpart OOOOa.** Except as provided in paragraphs (b)(11) and (12) of 40 CFR §60.5416a, the permittee must inspect each closed vent system according to the procedures and schedule specified in paragraphs a. and b. of this condition, inspect each cover according to the procedures and schedule specified in paragraph c. of this condition, and inspect each bypass device according to the procedures of paragraph d. of this condition for reciprocating compressors complying with condition 14.1.8.a.3.

a. For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the permittee must meet the requirements specified in paragraphs a.1. and 2. of this section.

1. Conduct an initial inspection according to the test methods and procedures specified in condition 14.3.4. to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in condition 14.3.4. to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

b. For closed vent system components other than those specified in paragraph a. of this section, the permittee must meet the requirements of paragraphs b.1. through 3. of this section.

1. Conduct an initial inspection according to the test methods and procedures specified in condition 14.3.4. to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

2. Conduct annual inspections according to the test methods and procedures specified in condition 14.3.4. to demonstrate that the components or connections operate with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

3. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

c. For each cover, the permittee must meet the requirements in paragraphs c.1. and 2. of this condition.

1. Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, the permittee must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

2. The permittee must initially conduct the inspections specified in paragraph c.1. of this condition following the installation of the cover. Thereafter, the permittee must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of 40 CFR §60.5416a. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(7).

d. For each bypass device, except as provided for in 40 CFR §60.5411a(a)(3)(ii), the permittee must meet the requirements of paragraph d.1. or 2. of this section.

1. Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

2. If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. The permittee must maintain records of the inspections according to 40 CFR §60.5420a(c)(8).

[45CSR16; 40 CFR §60.5416a(a)]

14.3.4. **No detectable emissions test methods and procedures under Subpart OOOOa.** If the permittee is required to conduct an inspection of a closed vent system or cover at the reciprocating compressor affected facility as specified in paragraph (a)(1), (2), or (3) of 40 CFR §60.5416a, the permittee must meet the requirements of paragraphs (b)(1) through (13) of 40 CFR §60.5416a.
[45CSR16; 40 CFR §60.5416a(b)]

14.3.5. **Test methods and procedures for reciprocating compressor affected facilities under Subpart OOOOb.**

a. The permittee must use one of the methods described in paragraphs a.1. or 2. of this condition to screen for emissions or leaks from the reciprocating compressor rod packing when complying with 40 CFR §60.5385b(b)(1)(iii).

1. **OGI instrument.** Use an OGI instrument for equipment leak detection as specified in paragraph a.1.i. of this condition. For the purposes of paragraph a.1.i. of this condition, any visible emissions observed by the OGI instrument from reciprocating rod packing is a leak.

i. **OGI instrument as specified in Appendix K of 40 CFR 60.** For reciprocating compressor affected facilities located at onshore natural gas processing plants, use an OGI instrument to screen for emissions from reciprocating rod packing in accordance with the protocol specified in Appendix K of 40 CFR 60.

2. **Method 21.** Use Method 21 in Appendix A-7 to 40 CFR 60 according to 40 CFR §60.5403b(b)(1) and (2). For the purposes of this condition, an instrument reading of 500 parts per million by volume (ppmv) above background or greater is a leak.

b. The permittee must determine natural gas volumetric flow rate using a rate meter which meets the requirement in Method 2D in Appendix A-1 of 40 CFR 60. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D.

c. The permittee must use a high-volume sampler to measure emissions of the reciprocating compressor rod packing, in accordance with 40 CFR §§60.5386b(c)(1) through (7).

d. As an alternative to a high-volume sampler, the permittee may use any other method that has been validated in accordance with the procedures specified in Method 301 in Appendix A in 40 CFR 63, subject to Administrator approval, as specified in 40 CFR §60.8(b).

[45CSR16; 40 CFR §§60.5386b(a), (a)(1), (a)(1)(i), (a)(2), and (b) to (d)]

14.3.6. **Performance testing procedures for control devices used to demonstrate compliance with the emission standards for reciprocating compressor and process unit equipment affected facilities.** The permittee must demonstrate that a control device achieves the performance requirements of 40 CFR §60.5412b(a)(1) or (2) using the performance methods and procedures specified in 40 CFR §60.5413b.
[45CSR16; 40 CFR §60.5413b]

14.3.7. **Inspections for closed vent systems, covers, and bypass devices at reciprocating compressor and process unit equipment affected facilities under Subpart OOOOb.** If the permittee installs a control device or routes emissions to a process, the permittee must inspect each closed vent system according to the procedures and schedule specified in paragraphs a. and b. of this condition, inspect each cover according to the procedures and schedule specified in paragraph c. of this condition, and inspect each bypass device according to the procedures of paragraph d. of this condition, except as provided in 40 CFR §§60.5416b(b)(7) and (8).

a. For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the permittee must meet the requirements specified in paragraphs a.1. through 3. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416b(b) to demonstrate that the closed vent system operates with no identifiable emissions within the first 30 calendar days after startup of the affected facility routing emissions through the closed vent system.

2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in 40 CFR §60.5416b(b) to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

3. Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in 40 CFR §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with inspections required by paragraph a.2. of this condition.

b. For closed vent system components other than those specified in paragraph a.1. of this condition, the permittee must meet the requirements of paragraphs b.1. through 4. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416b(b) within the first 30 calendar days after startup of the affected facility routing emissions

through the closed vent system to demonstrate that the closed vent system operates with no identifiable emissions.

2. Conduct inspections according to the test methods, procedures, and frequencies specified in 40 CFR §60.5416b(b) to demonstrate that the components or connections operate with no identifiable emissions.

3. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in 40 CFR §60.5416b(b) to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

4. Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in 40 CFR §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph b.3. of this condition.

c. For each cover, the permittee must meet the requirements of paragraphs c.1. through 4. of this condition.

1. Conduct the inspections specified in c.2. through 4. of this condition to identify defects that could result in air emissions and to ensure the cover operates with no identifiable emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, the permittee must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

2. An initial inspection according to the test methods and procedures specified in 40 CFR §60.5416b(b), following installation of the cover to demonstrate that each cover operates with no identifiable emissions.

3. Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in 40 CFR §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph a.2. of this condition.

4. Inspections according to the test methods, procedures, and schedules specified in 40 CFR §60.5416b(b) to demonstrate that each cover operates with no identifiable emissions.

d. For each bypass device, except as provided for in 40 CFR §60.5411b(a)(4)(ii), the permittee must meet the requirements of paragraphs d.1. or 2. of this condition.

1. Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device and to the atmosphere.

2. If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device.

[45CSR16; 40 CFR §60.5416b(a)]

14.3.8. **No identifiable emissions test methods and procedures under Subpart OOOOb.** If the permittee is required to conduct an inspection of a closed vent system and cover as specified in 40 CFR §60.5416b(a)(1), (2), or (3) or 40 CFR §60.5398b(b), the permittee must meet the requirements of 40 CFR §§60.5416b(b)(1) through (9).
[45CSR16; 40 CFR §60.5416b(b)]

14.4. Recordkeeping Requirements

FUG AREAS 1 through 4 (40 CFR 60, Subpart OOOOa)

14.4.1. The permittee must comply with the requirements of condition 14.4.2. in addition to the requirements of 40 CFR §60.486a.
[45CSR16; 40 CFR §60.5421a(a)]

14.4.2. The following recordkeeping requirements apply to pressure relief devices subject to the requirements of 40 CFR §60.5401a(b)(1).

a. When each leak is detected as specified in 40 CFR §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

b. When each leak is detected as specified in 40 CFR §60.5401a(b)(2), the information specified in paragraphs b.1. through 10. of this condition must be recorded in a log and shall be kept for 2 years in a readily accessible location:

1. The instrument and operator identification numbers and the equipment identification number.

2. The date the leak was detected and the dates of each attempt to repair the leak.

3. Repair methods applied in each attempt to repair the leak.

4. “Above 500 ppm” if the maximum instrument reading measured by the methods specified in 40 CFR §60.5400a(d) after each repair attempt is 500 ppm or greater.

5. “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

6. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

7. The expected date of successful repair of the leak if a leak is not repaired within 15 days.

8. Dates of process unit shutdowns that occur while the equipment is unrepaired.

9. The date of successful repair of the leak.

10. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR §60.482-4a(a). The designation of equipment subject to the provisions of 40 CFR §60.482-4a(a) must be signed by the owner or operator.

[45CSR16; 40 CFR §60.5421a(b)]

FUG AREAS 5 through 7 (40 CFR 60, Subpart OOOOb)

14.4.3. **Recordkeeping requirements for process unit equipment affected facilities under Subpart OOOOb.** The permittee must maintain a record of each equipment leak monitoring inspection and each leak identified under 40 CFR §60.5400b and §60.5401b as specified in paragraphs b.1. through 17. of this condition. The record must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

a. The permittee may comply with the recordkeeping requirements for multiple process unit equipment affected facilities in one recordkeeping system if the system identifies each record by each facility.

b. The permittee must maintain the monitoring inspection records specified in paragraphs b.1. through 17. of this section.

1. Equipment Identification. Note that connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of 40 CFR 60, Subpart OOOOb are identified as a group, and the number of connectors subject is indicated.

2. Date and start and end times of the monitoring inspection.

3. Inspector name.

4. Leak determination method used for the monitoring inspection (i.e., OGI, Method 21, or AVO).

5. Monitoring instrument identification (OGI and Method 21 only).

6. Type of equipment monitored.

7. Process unit identification.

8. The records specified in Section 12 of Appendix K of 40 CFR 60, for each monitoring inspection conducted with OGI.

9. The records in paragraph b.9.i. through vii., for each monitoring inspection conducted with Method 21 of Appendix A-7 to 40 CFR 60.

i. Instrument reading.

ii. Date and time of instrument calibration and initials of operator performing the calibration.

iii. Calibration gas cylinder identification, certification date, and certified concentration.

iv. Instrument scale used.

v. A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of Appendix A-7 to 40 CFR 60.

vi. Results of the daily calibration drift assessment.

vii. If the permittee makes the calibration gas, a description of the procedure used.

10. For visual inspections of pumps in light liquid service, keep the records specified in paragraphs b.10.i. through iii., for each monitored equipment:

i. Date of inspection.

ii. Inspector name.

iii. Result of inspection (i.e., visual indications of liquids dripping from the pump seal or no visual indications of liquids dripping from the pump seal).

11. For each leak detected, the records specified in paragraphs b.11.i. through v. of this condition:

i. The instrument and operator identification numbers and the process unit and equipment identification numbers. For leaks identified via AVO methods, enter the specific sensory method for instrument identification number.

ii. The date the leak was detected.

iii. For each attempt to repair the leak, record:

a. The date.

b. The repair method applied.

c. Indication of whether a leak was still detected following each attempt to repair the leak.

iv. The date of successful repair of the leak and the method of monitoring used to confirm the repair, as specified in paragraph b.11.iv.a. through c. of this condition.

a. If Method 21 of Appendix A-7 to 40 CFR 60 is used to confirm the repair, maintain a record of the maximum instrument reading measured by Method 21 of Appendix A-7 to 40 CFR 60.

b. If OGI conducted in accordance with Appendix K of 40 CFR 60 is used to confirm the repair, maintain a record of video footage of the repair confirmation.

c. If the leak is repaired by eliminating AVO indications of a leak, maintain a record of the specific sensory method used to confirm that the evidence of the leak is eliminated.

v. For each repair delayed beyond 15 calendar days after detection of the leak, record:

a. "Repair delayed" and the reason for the delay.

b. The signature of the certifying official who made the decision that repair could not be completed without a process shutdown.

c. The expected date of successful repair of the leak.

d. Dates of process unit shutdowns that occur while the equipment is unrepaired.

12. A list of identification numbers for equipment that are designated for no detectable emissions complying with the provisions of 40 CFR §60.5401b.

13. A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

14. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

15. A list of identification numbers for equipment that is in vacuum service.

16. A list of identification numbers for equipment designated as having the potential to emit methane or VOC less than 300 hr/yr.

17. A list of identification numbers for valves where it was infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was infeasible.

[45CSR16; 40 CFR §60.5421b]

Compressors

14.4.4. **Recordkeeping requirements under Subpart OOOO.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in paragraphs a. through e. of this condition. All records required by 40 CFR 60, Subpart OOOO must be maintained either onsite or at the nearest local field office for at least 5 years.

a. For each reciprocating compressor affected facility, the permittee must maintain the following records:

1. Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

2. Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in 40 CFR §60.5385(a)(3).

3. Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in 40 CFR §60.5385.

b. Records of each closed vent system inspection required under 40 CFR §§60.5416(a)(1) and (2) for reciprocating compressors.

c. A record of each cover inspection required under 40 CFR §60.5416(a)(3) for reciprocating compressors.

d. If the permittee is subject to the bypass requirements of 40 CFR §60.5416(a)(4) for reciprocating compressors, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

e. If the permittee is subject to the closed vent system no detectable emissions requirements of 40 CFR §60.5416(b) for reciprocating compressors, a record of the monitoring conducted in accordance with 40 CFR §60.5416(b).

[45CSR16; 40 CFR §§60.5420(c), (c)(3), (c)(6), (c)(7), (c)(8), and (c)(9)]

14.4.5. **Recordkeeping requirements under Subpart OOOOa.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in paragraphs a. through e. of this condition. All records required by 40 CFR 60, Subpart OOOOa must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60, Subpart OOOOa that are submitted electronically via the EPA's CDX may be maintained in electronic format.

a. For each reciprocating compressor affected facility, the permittee must maintain the records in paragraphs a.1. through 3. of this condition.

1. Records of the cumulative number of hours of operation or number of months since initial startup or since the previous replacement of the reciprocating compressor rod packing, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

2. Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in 40 CFR §60.5385a(a)(3).

3. Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in 40 CFR §60.5385a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

b. Records of each closed vent system inspection required under 40 CFR §§60.5416a(a)(1) and (2) and (b) for reciprocating compressors as required in paragraphs b.1. through 3. of this condition.

1. A record of each closed vent system inspection or no detectable emissions monitoring survey. The permittee must include an identification number for each closed vent system (or other unique identification description selected) and the date of the inspection.

2. For each defect or leak detected during inspections required by 40 CFR §§60.5416a(a)(1) and (2), (b), (c)(1), or (d), the permittee must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of Appendix A-7 of 40 CFR 60, the date of detection, and the date the repair to correct the defect or leak is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416a(b)(10), the permittee must record the reason for the delay and the date the repair is expected to be completed.

c. A record of each cover inspection required under 40 CFR §60.5416a(a)(3) for reciprocating compressors as required in paragraphs c.1. through 3. of this condition.

1. A record of each cover inspection. The permittee must include an identification number for each cover (or other unique identification description selected) and the date of the inspection.

2. For each defect detected during inspections required by 40 CFR §60.5416a(a)(3), the permittee must record the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and the date the repair to correct the defect is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416a(b)(10), the permittee must record the reason for the delay and the date the repair is expected to be completed.

d. If the permittee is subject to the bypass requirements of 40 CFR §60.5416a(a)(4) for reciprocating compressors, the permittee must prepare and maintain a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

e. For each closed vent system routing to a control device or process, the records of the assessment conducted according to 40 CFR §60.5411a(d):

1. A copy of the assessment conducted according to 40 CFR §60.5411a(d)(1);

2. A copy of the certification according to 40 CFR §60.5411a(d)(1)(i); and

3. The owner or operator shall retain copies of all certifications, assessments, and any related records for a period of five years and make them available if directed by the delegated authority.

[45CSR16; 40 CFR §§60.5420a(c)(3), (c)(6), (c)(7), (c)(8), and (c)(17)]

14.4.6. **Recordkeeping requirements under Subpart OOOOb.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in 40 CFR §§60.5420b(c)(1) through (15). All records required by 40 CFR 60, Subpart OOOOb must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60, Subpart OOOOb that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain

electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

For each reciprocating compressor affected facility, the permittee must maintain the records in paragraphs a. through j. of this condition and in condition 14.4.7., as applicable. If complying with an alternative GHG and VOC standard under 40 CFR §60.5398b, in lieu of the information specified in condition 14.4.7.a., the permittee must provide the information specified in 40 CFR §60.5424b.

a. For each reciprocating compressor affected facility, the permittee must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in 40 CFR §60.5385b, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

b. Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in 40 CFR §60.5385b(d).

c. Records of the cumulative number of hours of operation since initial startup or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

d. A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

e. Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs e.1. through 6. of this condition.

    1. Description of standard method published by a consensus-based standards organization or industry standard practice.

    2. Records of volumetric flow rate calculations conducted according to 40 CFR §60.5385b(b) or (c), as applicable.

    3. Records of manufacturer operating procedures and measurement methods.

    4. Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

    5. Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. The permittee must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

    6. Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

f. Date when performance-based volumetric flow rate is exceeded.

g. The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

h. Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

i. For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

j. Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

[45CSR16; 40 CFR §§60.5420b(c) and (c)(5)]

14.4.7. **Additional recordkeeping requirements for reciprocating compressor and process unit equipment affected facilities under Subpart OOOOb.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in 40 CFR §§60.5420b(c)(1) through (15). All records required by 40 CFR 60, Subpart OOOOb must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60, Subpart OOOOb that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

a. Records of each closed vent system inspection required under 40 CFR §§60.5416b(a)(1), (a)(2), and (b) for reciprocating compressor and process unit equipment affected facilities as required in paragraphs a.1. through 4. of this condition.

1. A record of each closed vent system inspection or no identifiable emissions monitoring survey. The permittee must include an identification number for each closed vent system (or other unique identification description selected by the permittee), the date of the inspection, and the method used to conduct the inspection (i.e., visual, AVO, OGI, Method 21 of Appendix A-7 to 40 CFR 60).

2. For each defect or emissions detected during inspections required by 40 CFR §§60.5416b(a)(1) and (2) or (b), the permittee must record the location of the defect or emissions; a description of the defect; the maximum concentration reading obtained if using Method 21 of Appendix A-7 to 40 CFR 60; the indication of emissions detected by AVO if using AVO; the date of detection; the date of each attempt to repair the emissions or defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect or emissions is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416b(b)(6), the permittee must record the reason for the delay and the date the repair is expected to be completed.

4. Parts of the closed vent system designated as unsafe to inspect as described in 40 CFR §60.5416b(b)(7) or difficult to inspect as described in 40 CFR §60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the closed vent system.

b. A record of each cover inspection required under 40 CFR §60.5416b(a)(3) for the reciprocating compressor as required in paragraphs b.1. through 4. of this condition.

1. A record of each cover inspection. The permittee must include an identification number for each cover (or other unique identification description selected), the date of the inspection, and the method used to conduct the inspection (i.e., AVO, OGI, Method 21 of Appendix A-7 to 40 CFR 60).

2. For each defect detected during the inspection, the permittee must record the location of the defect; a description of the defect, the date of detection, the maximum concentration reading obtained if using Method 21 of Appendix A-7 to 40 CFR 60; the indication of emissions detected by AVO if using AVO; the date of each attempt to repair the defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416b(b)(6), the permittee must record the reason for the delay and the date the repair is expected to be completed.

4. Parts of the cover designated as unsafe to inspect as described in 40 CFR §60.5416b(b)(7) or difficult to inspect as described in 40 CFR §60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the cover.

c. For each bypass subject to the bypass requirements of 40 CFR §60.5416b(a)(4), the permittee must maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance the key is checked out; date and time of each instance the alarm is sounded.

d. Records for each control device used to comply with the emission reduction standard in 40 CFR §60.5385b(d)(2) for reciprocating compressor affected facilities or 40 CFR §§60.5400b(f) or 60.5401b(e) for the process equipment affected facilities, as required in 40 CFR §§60.5420b(c)(11)(i) through (viii). If using an enclosed combustion device or flare using an alternative test method approved under 40 CFR §60.5412b(d), keep records of the information in 40 CFR §60.5420b(c)(11)(ix), in lieu of the records required by 40 CFR §§60.5412b(c)(11)(i) through (iv) and (vi) through (viii).

e. For each closed vent system routing to a control device or process, the records of the assessment conducted according to 40 CFR §60.5411b(c):

1. A copy of the assessment conducted according to 40 CFR §60.5411b(c)(1); and

2. A copy of the certification according to 40 CFR §§60.5411b(c)(1)(i) and (ii).

f. A copy of each performance test submitted under 40 CFR §60.5420b(b)(12) or (b)(13).

[45CSR16; 40 CFR §§60.5420b(c) and (c)(8) to (c)(13)]

14.5. Reporting Requirements

FUG AREAS 1 through 4 (40 CFR 60, Subpart OOOOa)

14.5.1. The permittee must comply with the requirements of conditions 14.5.2. and 14.5.3. in addition to the requirements of 40 CFR §§60.487a(a), (b)(1) through (3), and (c)(2)(i) through (iv). The permittee must

submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for 40 CFR 60, Subpart OOOOa or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to 40 CFR 60, Subpart OOOOa is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available in CEDRI for at least 90 days, the permittee must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in 40 CFR 60, Subpart OOOOa, regardless of the method in which the report is submitted.
[45CSR16; 40 CFR §60.5422a(a)]

14.5.2. An owner or operator must include the following information in the initial semiannual report in addition to the information required in 40 CFR §§60.487a(b)(1) through (3): Number of pressure relief devices subject to the requirements of 40 CFR §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of 40 CFR §60.482-4a(a) and those pressure relief devices complying with 40 CFR §60.482-4a(c).
[45CSR16; 40 CFR §60.5422a(b)]

14.5.3. An owner or operator must include the information specified in paragraphs a. and b. of this condition in all semiannual reports in addition to the information required in 40 CFR §§60.487a(c)(2)(i) through (iv):

a. Number of pressure relief devices for which leaks were detected as required in 40 CFR §60.5401a(b)(2); and

b. Number of pressure relief devices for which leaks were not repaired as required in 40 CFR §60.5401a(b)(3).

[45CSR16; 40 CFR §60.5422a(c)]

FUG AREAS 5 through 7 (40 CFR 60, Subpart OOOOb)

14.5.4. a. **Notification requirements.** The permittee must submit notifications according to paragraph a.1. of this condition for the process unit equipment affected facilities specified in 40 CFR §60.5365b that were constructed, modified, or reconstructed during the reporting period.

1. For a process unit equipment affected facility located at an onshore natural gas processing plant, the permittee must submit the notifications required in 40 CFR §§60.7(a)(1), (3), and (4) and 40 CFR §60.15(d).

[40 CFR §§60.5420b(a) and (a)(1)]

b. **Reporting requirements.** The permittee must submit annual reports containing the information specified in 40 CFR §§60.5420b(b)(1) through (b)(14) following the procedure specified in 40 CFR §60.5420b(b)(15). The permittee must submit performance test reports as specified in 40 CFR §60.5420b(b)(12) or (13), if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. The permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in 40 CFR §§60.5420b(b)(1) through (14). Annual reports may coincide with Title

V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

1. The general information specified in paragraphs b.1.i. through iv. of this condition is required for all reports.

   i. The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

   ii. An identification of each affected facility being included in the annual report.

   iii. Beginning and ending dates of the reporting period.

   iv. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

   [40 CFR §§60.5420b(b)(1) and (b)(1)(i) to (iv)]

2. For each process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, the permittee must submit the information in paragraphs b.2.i. through v. of this condition. For each process unit equipment which uses a closed vent system to route to a process, the permittee must submit the information in paragraphs b.2.i. through iv. of this condition.

   i. Dates of each inspection required under 40 CFR §§60.5416b(a) and (b).

   ii. Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

   iii. Date and time of each bypass alarm or each instance the key is checked out if the permittee is subject to the bypass requirements of 40 CFR §60.5416b(a)(4).

   iv. The permittee must submit the certification signed by the qualified professional engineer or in-house engineer according to 40 CFR §60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

v. If the permittee complies with the emissions standard for the process unit equipment affected facility with a control device, the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (L), unless an enclosed combustion device or flare is used an alternative test method approved under 40 CFR §60.5412b(d). If an enclosed combustion device or flare using an alternative test method approved under 40 CFR §60.5412b(d), the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (C) and (L) through (P).

[40 CFR §60.5420b(b)(11)]

3. Within 60 days after the date of completing each performance test (see 40 CFR §60.8) required by 40 CFR 60, Subpart OOOOb, except testing conducted by the manufacturer as specified in 40 CFR §60.5413b(d), the permittee must submit the results of the performance test following the procedures specified in 40 CFR §60.5420b(d). Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.
[40 CFR §60.5420b(b)(12)]

4. For combustion control devices tested by the manufacturer in accordance with 40 CFR §60.5413b(d), an electronic copy of the performance test results required by 40 CFR §60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*.
[40 CFR §60.5420b(b)(13)]

5. The permittee must submit the annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 40 CFR 60, Subpart OOOOb and following the procedure specified in 40 CFR §60.5420b(d). If the reporting form specific to 40 CFR 60, Subpart OOOOb is not available on the CEDRI website at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in 40 CFR 60, Subpart OOOOb, regardless of the method in which the report is submitted.
[40 CFR §60.5420b(b)(15)]

[45CSR16; 40 CFR §60.5420b(b)]

c. **Electronic reporting.** If the permittee is required to submit notifications or reports following the procedure specified in this paragraph, the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information you claim as CBI.
[45CSR16; 40 CFR §60.5420b(d)]

d. **Additional reporting requirements for process unit equipment affected facilities.**

1. The permittee must submit semiannual reports using the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart OOOOb and following the procedure specified in paragraph c. of this condition. If the reporting form specific to 40 CFR 60, Subpart OOOOb is not available on the CEDRI website at the time that the report is due, submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted within 45 days after the end of the semiannual reporting period, regardless of the method in which the report is submitted.

2. The initial semiannual report must include the following information:

i. The general information specified in paragraph d.3.i. of this condition.

ii. For each process unit:

a. Process unit identification.

b. Number of valves subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(f).

c. Number of pumps subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(b).

d. Number of connectors subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(h).

e. Number of pressure relief devices subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(c).

f. The information in 40 CFR §§60.5420b(c)(3) and (4).

3. All subsequent semiannual reports must include the following information:

i. The general information specified in paragraphs d.3.i.a. through c. of this condition.

a. The company name, facility site name, and address of the affected facility.

b. Beginning and ending dates of the reporting period.

c. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

ii. Process unit identification for each process unit.

iii. For each month during the semiannual reporting period for each process unit report:

a. Number of valves for which leaks were detected as described in 40 CFR §60.5400b(b) or §60.5401b(f).

b. Number of valves for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i), the number of instances where it was technically infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was technically infeasible.

c. Number of pumps for which leaks were detected as described 40 CFR §60.5400b(b) or §60.5401b(b).

d. Number of pumps for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

e. Number of connectors for which leaks were detected as described in 40 CFR §60.5400b(b) or §60.5401b(h).

f. Number of connectors for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

g. Number of pressure relief devices for which leaks were detected as described in 40 CFR §60.5400b(b) or §60.5401b(c).

h. Number of pressure relief devices for which leaks were not repaired as required in 40 CFR §60.5400b(h) or § 60.5401b(i).

i. Number of open-ended valves or lines for which leaks were detected as described in 40 CFR §60.5400b(e) or §60.5401b(d).

j. Number of open-ended valves or lines for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

k. Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were detected as described in 40 CFR §60.5400b(g) or §60.5401b(g).

l. Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

m. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

iv. Dates of process unit shutdowns which occurred within the semiannual reporting period.

v. Revisions to items reported according to paragraph d.2. of this condition if changes have occurred since the initial report or subsequent revisions to the initial report.

[45CSR16; 40 CFR §60.5422b]

Compressors

14.5.5. **Reporting requirements under Subpart OOOO.** The permittee must submit annual reports containing the information specified in paragraphs a. and b. of this condition to the Administrator and performance test reports as specified in paragraph (b)(7) of 40 CFR §60.5420. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs a. and b. of this condition. Annual reports may coincide with Title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

a. The general information specified in paragraphs a.1. through 4. of this condition.

1. The company name and address of the affected facility.

2. An identification of each affected facility being included in the annual report.

3. Beginning and ending dates of the reporting period.

4. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

b. For each reciprocating compressor affected facility, the information specified in paragraphs b.1. and 2. of this condition.

1. The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

2. Records of deviations specified in paragraph (c)(3)(iii) of 40 CFR §60.5420 that occurred during the reporting period.

[45CSR16; 40 CFR §§60.5420(b), (b)(1), and (b)(4)]

14.5.6. **Reporting requirements under Subpart OOOOa.** The permittee must submit annual reports containing the information specified in paragraphs (b)(1), (b)(4), and (b)(12) of 40 CFR §60.5420a. The permittee must submit annual reports following the procedure specified in paragraph (b)(11) of 40 CFR §60.5420a. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) and (12) of 40 CFR §60.5420a. Annual reports may coincide with Title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

a. The general information specified in paragraphs a.1. through 4. of this condition is required for all reports.

1. The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

2. An identification of each affected facility being included in the annual report.

3. Beginning and ending dates of the reporting period.

4. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

b. For each reciprocating compressor affected facility, the information specified in paragraphs b.1. through 3. of this condition.

1. The cumulative number of hours of operation or the number of months since initial startup or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

2. If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3)(iii) of 40 CFR §60.5420a, the date and time the deviation began, duration of the deviation, and a description of the deviation.

3. If required to comply with 40 CFR §60.5385a(a)(3), the information in paragraphs b.3.i. through iii. of this condition.

i. Dates of each inspection required under 40 CFR §§60.5416a(a) and (b);

ii. Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

iii. Date and time of each bypass alarm or each instance the key is checked out if subject to the bypass requirements of 40 CFR §60.5416a(a)(4).

c. The permittee must submit reports to the EPA via CEDRI, except as outlined in 40 CFR §60.5420a(b)(11). CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The permittee must use the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart OOOOa (*https://www.epa.gov/electronic-reporting-air-emissions/cedri/*). If the reporting form specific to 40 CFR 60, Subpart OOOOa is not available on the CEDRI website at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available in CEDRI for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the reports must be submitted by the deadlines specified in 40 CFR 60, Subpart OOOOa, regardless of the method in which the reports are submitted. The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information claimed as CBI. Although we do not expect persons to assert a claim of CBI, if the permittee wishes to assert a CBI claim for some of the information in the report, submit a complete file using the appropriate electronic report template on the CEDRI website, including information claimed to be CBI, to the EPA following the procedures in 40 CFR §§60.5420a(b)(11)(i) and (ii). Clearly mark the part or all of the information claimed to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. Submit the same file submitted to the CBI office with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in 40 CFR §60.5420a(b)(11).

1. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov* and, as described above, should include clear CBI markings. Files should be flagged to the attention of the Oil and Natural Gas Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if the permittee does not have a file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

2. If the permittee cannot transmit the file electronically, the permittee may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Oil and Natural Gas Sector Lead, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

d. The permittee must submit the certification signed by the qualified professional engineer or in-house engineer according to 40 CFR §60.5411a(d) for each closed vent system routing to a control device or process.

[45CSR16; 40 CFR §§60.5420a(b), (b)(1), (b)(4), (b)(11), and (b)(12)]

14.5.7. a. **Notification requirements under Subpart OOOOb.** The permittee must submit notifications according to paragraph a.1. of this condition for reciprocating compressor affected facilities specified in 40 CFR §60.5365b that were constructed, modified, or reconstructed during the reporting period.

1. For a reciprocating compressor affected facility, the permittee is not required to submit the notifications required in 40 CFR §§60.7(a)(1), (3), and (4) and 40 CFR §60.15(d).

[40 CFR §§60.5420b(a) and (a)(1)]

b. **Reporting requirements under Subpart OOOOb.** The permittee must submit annual reports containing the information specified in 40 CFR §§60.5420b(b)(1), (b)(6), and (b)(11) through (b)(13) following the procedure specified in 40 CFR §60.5420b(b)(15). The permittee must submit performance test reports as specified in 40 CFR §60.5420b(b)(12) or (13), if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. The permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in 40 CFR §§60.5420b(b)(1) through (14). Annual reports may coincide with Title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

1. The general information specified in paragraphs b.1.i. through iv. of this condition is required for all reports.

i. The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

ii. An identification of each affected facility being included in the annual report.

iii. Beginning and ending dates of the reporting period.

iv. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

[40 CFR §§60.5420b(b)(1) and (b)(1)(i) to (iv)]

2. For each reciprocating compressor affected facility, the information specified in paragraphs b.2.i. through vii. of this condition, as applicable.

   i. The cumulative number of hours of operation since initial startup, since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting the volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

   ii. If applicable, for each deviation that occurred during the reporting period and recorded as specified in 40 CFR §60.5420b(c)(5)(i), the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, the permittee must include a statement that no deviations occurred during the reporting period.

   iii. A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

   iv. If complying with 40 CFR §60.5385b(d)(1) or (2), the information in paragraphs b.3.i. through iv. of this condition. If complying by routing emissions to a control device, as required in 40 CFR §60.5385b(d)(2), the information in paragraph b.3.v. of this condition.

   v. Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

   vi. Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

   vii. If complying with an alternative GHG and VOC standard under 40 CFR §60.5398b, in lieu of the information specified in paragraphs b.3.i. and ii. of this condition, the permittee must provide the information specified in 40 CFR §60.5424b.

   [40 CFR §60.5420b(b)(6)]

3. For each reciprocating compressor affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, the permittee must submit the information in paragraphs b.3.i. through v. of this condition. For each reciprocating compressor which uses a closed vent system to route to a process, the permittee must submit the information in paragraphs b.3.i. through iv. of this condition. For each reciprocating compressor equipped with a cover, the permittee must submit the information in paragraphs b.3.i. and ii. of this condition.

   i. Dates of each inspection required under 40 CFR §§60.5416b(a) and (b).

   ii. Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

   iii. Date and time of each bypass alarm or each instance the key is checked out if the permittee is subject to the bypass requirements of 40 CFR §60.5416b(a)(4).

iv. The permittee must submit the certification signed by the qualified professional engineer or in-house engineer according to 40 CFR §60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

v. If the permittee complies with the emissions standard for the reciprocating compressor affected facility with a control device, the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (L), unless an enclosed combustion device or flare is used an alternative test method approved under 40 CFR §60.5412b(d). If the permittee uses an enclosed combustion device or flare using an alternative test method approved under 40 CFR §60.5412b(d), the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (C) and (L) through (P).

[40 CFR §60.5420b(b)(11)]

4. Within 60 days after the date of completing each performance test (see 40 CFR §60.8) required by 40 CFR 60, Subpart OOOOb, except testing conducted by the manufacturer as specified in 40 CFR §60.5413b(d), the permittee must submit the results of the performance test following the procedures specified in 40 CFR §60.5420b(d). Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.
[40 CFR §60.5420b(b)(12)]

5. For combustion control devices tested by the manufacturer in accordance with 40 CFR §60.5413b(d), an electronic copy of the performance test results required by 40 CFR §60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*.
[40 CFR §60.5420b(b)(13)]

6. The permittee must submit the annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 40 CFR 60, Subpart OOOOb and following the procedure specified in 40 CFR §60.5420b(d). If the reporting form specific to 40 CFR 60, Subpart OOOOb is not available on the CEDRI website at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.
[40 CFR §60.5420b(b)(15)]

[45CSR16; 40 CFR §60.5420b(b)]

c. **Electronic reporting.** If the permittee is required to submit notifications or reports following the procedure specified in this paragraph, the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information you claim as CBI.
[45CSR16; 40 CFR §60.5420b(d)]

14.6. Compliance Plan

14.6.1. None

15.0 NPP: Turbines and Duct Burners [emission point ID(s): TB1A/B to TB4A/B]

15.1. Limitations and Standards

15.1.1. **Combustion Turbines**

The combustion turbines (CTs) shall meet the following requirements:

a. R13-3493 only authorizes construction and operation of one (1) set of the four (4) same make/model CTs defined as either "Scenario A" or "Scenario B" under the table titled "Natrium Power Plant" in Section 1.1. of this permit. This permit does not authorize any scenario where more than four (4) CTs are authorized.

b. Each group of authorized CTs shall be the make, model, and size as specified under the "Natrium Power Plant" table and shall only be fired by pipeline-quality natural gas, ethane, or some combination thereof.

c. With the exception of operation during times defined as "startup" or "shutdown" pursuant to 15.2.1., at all times each CT is in operation, each unit shall be controlled by Selective Catalytic Reduction (SCR) for control of NO_X emissions and an Oxidation Catalyst for control of CO and unburnt hydrocarbon (UHC) emissions.

d. Each CT shall be fired using good combustion practices. Good Combustion Practices shall mean activities such as maintaining operating logs and recordkeeping, conducting training, ensuring maintenance knowledge, performing routine and preventive maintenance, conducting burner and control adjustments, monitoring fuel quality, etc.

e. The maximum emissions from each CT shall not exceed the limits (during the specific operational times) as given in the following table:

Table 15.1.1.e. – Scenario A: CT Emission Limits

GE LM6000PG SPRINT Emission Limits				
Pollutant	**lb/hr**			**ton/year**
	Startup	**Shutdown**	**Steady-State**	
CO	152.90	95.82	2.04	10.40
NO_X	41.86	41.86	3.35	15.13
$PM_{2.5}$/PM_{10}/PM[(1)]	3.19	3.19	3.86	16.91
SO_2	1.64	1.64	1.64	7.19
VOC	4.81	4.81	0.44	1.97
Formaldehyde	0.34	0.34	0.34	1.50
Total HAPs	0.49	0.49	0.49	2.17

(1) Includes condensables.

Table 15.1.1.e. – Scenario B: CT Emission Limits

Siemens SGT-800 Emission Limits				
Pollutant	**lb/hr**			**ton/year**
	Startup	**Shutdown**	**Steady-State**	
CO	51.84	12.48	0.61	10.74
NO_X	25.68	20.88	3.49	20.35
$PM_{2.5}/PM_{10}/PM$[(1)]	0.72	0.48	3.52	14.86
SO_2	1.69	1.69	1.69	7.39
VOC	2.88	0.48	0.35	1.86
Formaldehyde	0.13	0.13	0.13	0.57
Total HAPs	0.29	0.29	0.29	1.25

(1) Includes condensables.

f. The CTs shall each not operate in the modes defined as "startup" and "shutdown" (as defined under 15.2.1.) in excess of the annual hourly limits given in the following table:

Table 15.1.1.f.: CT Annual Startup/Shutdown Hours of Operation Limits

CT	Startup	Shutdown
GE LM6000PG SPRINT	12	12
Siemens SGT-800	256	256

g. At the time operation of the CTs commences, the permittee shall have, and make available to the Director upon request, guarantees from the appropriate equipment vendors that the following maximum emission rates are achievable from the equipment in question:

Table 15.1.1.g.: CT Vendor Guarantee Requirements (in ppmvd at 15% O_2)

Pollutant	GE LM6000PG SPRINT		Siemens SGT-800	
	Uncontrolled	**Controlled**	**Uncontrolled**	**Controlled**
CO	94.0	2.0	5.0	0.5
NO_X	25.0	2.0	35.0	1.8
$PM_{2.5}/PM_{10}/PM$	N/A	N/A	2.5	N/A
VOC	11.0	1.0	5.0	0.5
Formaldehyde	N/A	N/A	0.1	0.1

h. The amount of power supplied by each CT to the utility distribution systems (not used at the plant and supplied instead to the "grid") shall be less than 219,000 MW-hour per year.

[45CSR13, R13-3493, 4.1.2.a. to h.]

15.1.2. **Duct Burners**

The Duct Burners, identified as TB1A/B through TB4A/B, shall meet the following requirements:

a. Each Duct Burner will not exceed an MDHI of 475.1 MMBtu/hr and shall only be fired by pipeline-quality natural gas, ethane, or some combination thereof.

b. At all times each Duct Burner is in operation, the exhaust from each unit shall be controlled by Selective Catalytic Reduction (SCR) for control of NO_X emissions and an oxidation catalyst for control of CO and unburnt hydrocarbon (UHC) emissions. The Duct Burners shall not be operated during times defined as "startup" or "shutdown" pursuant to condition 15.2.1.

c. Each Duct Burner shall be fired using good combustion practices. Good combustion practices shall mean activities such as maintaining operating logs and recordkeeping, conducting training, ensuring maintenance knowledge, performing routine and preventative maintenance, conducting burner and control adjustments, monitoring fuel quality, etc.

d. The maximum emissions from each Duct Burner shall not exceed the limits as given in the following table.

Table 15.1.2.d.: Per-Duct Burner Emission Limits

Pollutant	lb/hour	ton/year
CO	2.12	1.86
NO_X	3.50	3.05
$PM_{2.5}$/PM_{10}/PM[(1),(2)]	3.65	3.19
SO_2[(3)]	0.28	0.24
VOC	0.13	0.11
Formaldehyde	0.03	0.03
Total HAPs	0.05	0.04

(1) Includes condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§§2-4.1. and -4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§§10-3.1. and -3.1.5.

e. At the time operation of the Duct Burners commences, the permittee shall have, and make available to the Director upon request, guarantees from the appropriate equipment vendors that the following maximum emission rates are achievable from the Duct Burners:

Table 15.1.2.e.: Duct Burner Vendor Guarantee Requirements (in ppmvd at 15% O_2)

Pollutant	Requirement
CO	2.0
NO_X	2.0
VOC	1.0

f. The Duct Burners shall each not combust in excess of 610.81 mmscf of fuel gas per year.

g. **45CSR2**
The Duct Burners are subject to the applicable limitations and standards under 45CSR2, including the requirements as given below under paragraphs g.1. through 5. of this condition.

1. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than 10 percent opacity based on a six-minute block average.
[45CSR§2-3.1.]

2. Compliance with the visible emission requirements of 45CSR§2-3.1. shall be determined in accordance with 40 CFR 60, Appendix A, Method 9 and 45CSR16 or by using measurements from continuous opacity monitoring systems approved by the Secretary. The Secretary may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of 45CSR§2-3.1. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.
[45CSR§2-3.2.]

3. No person shall cause, suffer, allow or permit the discharge of particulate matter into the open air from all fuel burning units located at one plant, measured in terms of pounds per hour in excess of the amount determined as follows:

   i. For Type "b" fuel burning units, the product of 0.09 and the total design heat inputs for such units in MMBtu/hr, provided however that no more than 600 lb/hr of particulate matter shall be discharged into the open air from all such units.

   [45CSR§§2-4.1. and -4.1.2.]

4. The addition of sulfur oxides to a combustion unit exit gas stream for the purpose of improving emissions control equipment efficiency shall be reviewed by the Secretary. No person shall cause, suffer, allow or permit the addition of sulfur oxides as described above unless written approval for such addition is provided by the Secretary.
[45CSR§2-4.4.]

5. At all times, including periods of startups, shutdowns and malfunctions, owners and operators shall, to the extent practicable, maintain and operate any fuel burning unit(s) 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 Secretary which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source.
[45CSR§2-9.2.]

h. **45CSR10**
The Duct Burners are subject to the applicable limitations and standards under 45CSR10, including the requirements in paragraph h.1. of this condition.

1. No person shall cause, suffer, allow or permit the discharge of sulfur dioxide into the open air from all stacks located at one plant, measured in terms of pounds per hour, in excess of the amount determined as follows:

   i. For Type "b" fuel burning units, the product of 3.1 and the total design heat inputs for such units discharging through those stacks in MMBtu/hr.

[45CSR§§10-3.1. and -3.1.5.]

[45CSR13, R13-3493, 4.1.3.a. to h.; 45CSR2; 45CSR10]

15.1.3. **40 CFR 60, Subpart KKKK**

The Combustion Turbines and Duct Burners shall meet all applicable requirements under 40 CFR 60, Subpart KKKK including the following:

a. The permittee must meet the emission limits for NO_X specified in Table 1 to Subpart KKKK of Part 60.

Table 1 to Subpart KKKK of Part 60 – Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Heat Input at Peak Load (HHV)	NO_X Emission Standard
New turbine firing natural gas	> 50 MMBtu/hr and ≤ 850 MMBtu/hr	25 ppm at 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh)
Turbines operating at less than 75 percent of peak load and turbines operating at temperatures less than 0°F	> 30 MW output	96 ppm at 15 % O_2 or 590 ng/J of useful output (4.7 lb/MWh)

[45CSR16; 40 CFR §60.4320(a); Table 1 to Subpart KKKK of Part 60]

b. The permittee must meet the emission limits for SO_2 specified in either paragraphs b.1. or 2. of this condition.

1. The permittee must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or

2. The permittee must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[45CSR16; 40 CFR §§60.4330(a), (a)(1), and (a)(2)]

c. The permittee must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. **[45CSR16; 40 CFR §60.4333(a)]**

[45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.1.4. **Control Devices**

Use of SCR systems and oxidation catalysts shall be in accordance with the following:

a. The SCR systems and oxidation catalysts shall be designed, operated and maintained according to good engineering practices and manufacturing recommendations so as to achieve, at a minimum, the following limits on each emission unit:

1. LM6000PG

i. NO_X: 2.0 ppmvd at 15% O_2

ii. CO: 2.0 ppmvd at 15% O_2

iii. VOCs: 1.0 ppmvd at 15% O_2

2. SGT-800

i. NO_X: 1.75 ppmvd at 15% O_2

ii. CO: 0.5 ppmvd at 15% O_2

iii. VOCs: 0.5 ppmvd at 15% O_2

iv. Formaldehyde: 0.1 ppmvd at 15% O_2

3. Duct Burner

i. NO_X: 2.0 ppmvd at 15% O_2

ii. CO: 2.0 ppmvd at 15% O_2

iii. VOCs: 1.0 ppmvd at 15% O_2

b. Catalyst performance shall be monitored and catalysts replaced according to good engineering practices and manufacturing recommendations.

c. The permittee shall operate each SCR in the optimal aqueous ammonia injection range as determined according to manufacturer recommendations or during the required performance testing. Ammonia/Urea slip from each SCR shall not exceed 5 ppmvd at 15% O_2.

[45CSR13, R13-3493, 4.1.7.a. to c.]

15.1.5. **45CSR40**

The Combustion Turbines must meet all applicable requirements for ozone season NO_X emissions under 45CSR40, including the following:

a. Ozone Season NO_X Emission Limitation – The owner or operator of a unit that meets the applicability requirements set forth in 45CSR§40-4.1. shall limit emissions of NO_X during an ozone season pursuant to a NO_X emission rate for each unit contained in Condition 4.1.2.e. of R13-3493.
[45CSR§40-5.1.]

b. The owner or operator of an applicable unit under 45CSR§40-4.1. shall install and operate a certified continuous emission monitoring system (CEMS) as necessary to attribute ozone season mass emissions of NO_X to each unit in accordance with 45CSR§40-6.5. Nitrogen oxides mass emissions measurements recorded and reported in accordance with 45CSR§40-6.5. shall be used to determine a unit's compliance with the ozone season NO_X emission limitation set forth in 45CSR§40-5.
[45CSR§40-6.1.]

c. An owner or operator of a combustion turbine unit that elects to demonstrate compliance using a CEMS shall meet the following requirements:

1. Install and certify the CEMS in accordance with Performance Specification 2 in Appendix B to 40 CFR 60 and 45CSR16;

2. Conduct the performance tests in accordance with 40 CFR §60.4400;

3. Operate and maintain the CEMS in accordance with 40 CFR §60.4345 on a continuous basis;

4. Collect all CEMS data in accordance with 40 CFR §60.4350;

5. For each month of the ozone season:

i. Determine total monthly heat input (in MMBtu) using fuel flowmeters and measurements or records of fuel gross calorific value, or in instances where fuel flow is not metered determine total monthly heat input (in MMBtu) from other measurements and records; and

ii. Calculate total monthly NO_X mass emissions (in tons) by multiplying the total monthly heat input by the 30-day rolling average NO_X emission rate (in lb/MMBtu) determined under 45CSR§§40-6.5.c. and -6.5.d. for the last day of the month on which the unit operated and divide by 2,000;

6. Determine the total NO_X mass emissions for the ozone season (in tons) by summing the amounts of total monthly NO_X mass emissions calculated under 45CSR§40-6.5.e. for each month of the ozone season; and

7. Comply with the following reporting and recordkeeping requirements:

i. Maintain records in accordance with 40 CFR §60.49b and all additional records necessary to support the heat input data, 30-day rolling average NO_X emission rate data, and NO_X mass emissions computations described in 45CSR§§40-6.5.e. and -6.5.f.; and

ii. Submit to the Secretary reports in accordance with 40 CFR §60.49b and include the total monthly heat input data, 30-day rolling average NO_X emission rate data, and monthly and ozone season NO_X mass emissions computations described in 45CSR§§40-6.5.e. and -6.5.f.

[45CSR§40-6.5.]

15.2. Monitoring Requirements

15.2.1. **Startup/Shutdowns.** For the purposes of demonstrating compliance with the maximum startup and shutdown operating hours as given under 15.1.1.f., the permittee shall monitor and record the monthly and rolling twelve (12) month total of hours each CT is operating in startup and shutdown mode. The record shall show the distinct hours of operation in each mode. "Startup" and "Shutdown" shall be defined as those periods where the exhaust temperature of the CTs is not sufficient for the SCR's and Oxidation Catalysts to effectively meet the limitations given under 15.1.4.
[45CSR13, R13-3493, Condition 4.2.3.]

15.2.2. **Grid Power Distribution.** For the purposes of demonstrating compliance with the maximum power export limitations as given under 15.1.1.h., the permittee shall monitor and record the monthly and rolling twelve (12) month total watts (in MW) exported to the power grid (i.e., not used for on-site power).
[45CSR13, R13-3493, Condition 4.2.4.]

15.2.3. **Duct Burner Fuel Usage.** For the purposes of demonstrating compliance with the maximum Duct Burner fuel usage limitations as given under 15.1.2.f., the permittee shall monitor and record the monthly and rolling twelve (12) month total of the volume of fuel used in each Duct Burner.
[45CSR13, R13-3493, Condition 4.2.5.]

15.2.4. a. **CEMS.** Within 60 days after achieving the maximum power generation rate at which the facility will be operated, but no later than 180 days after initial startup, the permittee shall, to show continuous compliance with the NO_X emission limits as given under Conditions 15.1.1.e., 15.1.1.g., 15.1.2.d., 15.1.2.e., and 15.1.4., install and operate a Continuous Emissions Monitoring System (CEMS) for monitoring the emissions of NO_X from each Combustion Turbine and Duct Burner. The CEMS shall be installed, maintained, and operated according to the applicable requirements given under 40 CFR 60, Subpart KKKK and any additional subparts referenced thereto. Data recorded by the CEMS shall be kept for a period not less than three (3) years and shall be made available to the Director or his/her representative upon request.
[45CSR13, R13-3493, Condition 4.2.6.; 45CSR§30-5.1.c.]

b. **40 CFR 60, Subpart KKKK Requirements for the NO_X CEMS.**

1. The permittee must install, calibrate, maintain, and operate the CEMS as described in 40 CFR §§60.4335(b) and 60.4345.

i. Install, certify, maintain and operate a CEMS consisting of a NO_X monitor and diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu).
[40 CFR §§60.4335(b) and (b)(1)]

ii. The following requirements for the NO_X CEMS equipment must be met:

a. Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in 40 CFR 60, Appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in 40 CFR 60, Appendix F is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to 40 CFR 75, Appendix A is acceptable for use under 40 CFR 60, Subpart KKKK. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

b. As specified in 40 CFR §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

c. Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to 40 CFR 75 are acceptable for use under 40 CFR 60, Subpart KKKK.

d. Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

e. The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs a., c., and d. of this condition. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in Section 1 of Appendix B to 40 CFR 75.

[40 CFR §60.4345]

[40 CFR §§60.4340(b) and (b)(1)]

2. For the purposes of identifying excess emissions using the continuous emission monitoring equipment:

i. All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).

ii. For each unit operating hour in which a valid hourly average, as described in 40 CFR §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of 40 CFR 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

iii. Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

iv. If the permittee has installed and certified a NO_X diluent CEMS to meet the requirements of 40 CFR 75, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under 40 CFR 60, Subpart KKKK. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c).

v. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

vi. Calculate the hourly average NO_X emission rates, in units of the emission standards under 40 CFR §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output-based standard.

a. For simple-cycle operation:

$$E = \frac{(NO_X)_h \times (HI)_h}{P} \quad \text{Eq. 1}$$

Where:
E = hourly NO_X emission rate, in lb/MWh,
$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,
$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in Appendix D to 40 CFR 75, and
P = gross energy output of the combustion turbine in MW.

b. For combined-cycle and combined heat and power complying with the output-based standard, use Eq. 1 in this condition, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad \text{Eq. 2}$$

Where:
P = gross energy output of the stationary combustion turbine system in MW,
$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW, and
$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW.

$$Ps = \frac{Q \times H}{3.413 \times 10^6\ Btu/MWh} \quad \text{Eq. 3}$$

Where:
Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electrical or mechanical output, in MW,
Q = measured steam flow rate in lb/hr,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions Btu/lb, and
3.413×10^6 = conversion from Btu/hr to MW, and
Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

c. For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL \times AL} \quad \text{Eq. 4}$$

Where:
E = NO_X emission rate in lb/MWh,
$(NO_X)_m$ = NO_X emission rate in lb/hr,
BL = manufacturer's base load rating of turbine, in MW, and
AL = actual load as a percentage of the base load.

vii. For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph f. of this condition to assess excess emissions on a 4-hour rolling average basis, as described in 40 CFR §60.4380(b)(1).

viii. For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph f. of this condition to assess excess emissions on a 30 unit operating day rolling average basis, as described in 40 CFR §60.4380(b)(1).

[40 CFR §60.4350]

[45CSR16; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.2.5. **45CSR2 Visual Emission Monitoring.** At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with 15.1.2.g. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.
[45CSR13, R13-3493, 4.2.7.]

15.2.6. **Control Devices.** The permittee shall meet the following monitoring, compliance demonstration, recording, and reporting requirements for the oxidation catalysts:

a. The permittee shall regularly inspect, properly maintain and/or replace catalytic reduction devices to ensure functional and effective operation of each unit. The permittee shall ensure proper operation, maintenance and performance of catalytic reduction devices by following the catalyst manufacturer emissions related operating and maintenance recommendations, or develop, implement, or follow a site-specific maintenance plan.

b. To demonstrate compliance with paragraph a. of this condition., the permittee shall maintain a copy of the site-specific maintenance plan or manufacturer maintenance plan.

[45CSR13, R13-3493, 4.2.8.]

15.2.7. **40 CFR 60, Subpart KKKK Requirements for SO_2 Monitoring.**

a. The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. The permittee must use one of the sources of information specified in paragraph a.1. of this condition to make the required demonstration:

1. The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet.

[40 CFR §§60.4365 and 60.4365(a)]

b. The permittee must conduct an initial performance test, as required in 40 CFR §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies listed in 40 CFR §60.4415(a) that the permittee may use to conduct the performance tests.

1. The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility.

[40 CFR §§60.4415(a) and (a)(1)]

[45CSR16; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.2.8. **CAM Compliance Demonstration for CO Emissions.** At all times that the turbines and/or duct burners are in operation, the catalyst bed inlet temperature shall be monitored via thermocouple. The thermocouple shall have a minimum accuracy within the range of ±0.01% to ±0.25% of the span. The temperature data shall be monitored and recorded every 24 hours of operation.

For the purposes of CAM, an excursion shall be defined as follows:

a. Prior to the initial performance test, an excursion occurs when the inlet temperature is outside of the manufacturer's recommended range. ~~The expected catalyst bed operating temperature is 650°F to 700°F.~~

b. Following the initial performance test, an excursion occurs when the inlet temperature is outside of the range established in the performance test.

[45CSR§30-5.1.c.; 40 CFR §64.6(c)]

15.2.9. **Commencement of Operation.** The owner or operator shall conduct the monitoring required under 40 CFR 64 upon issuance of a part 70 or 71 permit that includes such monitoring, or by such later date specified in the permit pursuant to 40 CFR §64.6(d).
[45CSR§30-5.1.c.; 40 CFR §64.7(a)]

15.2.10. **Proper Maintenance.** At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[45CSR§30-5.1.c; 40 CFR §64.7(b)]

Page: 147

Number: 1 Author: DWheeler Subject: Cross-Out Date: 6/24/2025 11:29:43 AM

15.2.11. **Continued Operation.** Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of 40 CFR 64, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR§30-5.1.c.; 40 CFR §64.7(c)]

15.2.12. **Response to Excursions or Exceedances.**

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[45CSR§30-5.1.c.; 40 CFR §64.7(d)]

15.2.13. **Documentation of Need for Improved Monitoring.** After approval of monitoring under 40 CFR 64, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the 40 CFR 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

[45CSR§30-5.1.c.; 40 CFR §64.7(e)]

15.2.14. **Quality Improvement Plan (QIP).** Based on the results of the determination made under Condition 15.2.12.b., the Administrator or the permitting authority may require the permittee to develop and implement a QIP. If required, the QIP shall be developed and implemented in accordance with 40 CFR §§64.8(b) through (e).
[45CSR§30-5.1.c.; 40 CFR §64.8]

15.3. Testing Requirements

15.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established in this permit and/or applicable regulations.
[45CSR13, R13-3493, 4.3.1.]

15.3.2. **Combustion Turbines/Duct Burners.** The permittee shall meet the following performance testing requirements with respect to the combustion turbines (CT):

a. The permittee shall, pursuant to the timing and other requirements of 40 CFR 60, Subpart KKKK, conduct, or have conducted, performance testing on each CT and Duct Burner to determine the emission rates of NO_X, during operation in non-startup/shutdown mode (as defined under 15.2.1.). The testing shall, in addition to meeting all applicable requirements under 40 CFR 60, Subpart KKKK, be in accordance with 3.3.1. Results of the performance testing shall, unless granted in writing a waiver by the Director, be used to determine compliance with the NO_X emission limits given under 15.1.1.e. and 15.1.2.d. After the initial test, subsequent NO_X performance testing shall be conducted annually (no more than 14 months following the previous test) unless the previous results demonstrate that the affected units achieved compliance of less than or equal to 75 percent of the applicable emission limits, then the permittee may reduce the frequency of subsequent tests to once every two years (no more than 26 calendar months following the previous test); and
[45CSR16; 40 CFR §60.4340(a)]

b. In addition to the required performance testing under 15.3.2.a., the permittee shall, within 60 days after achieving the maximum capacity each CT/Duct Burner combination will be operated, but not later than 180 days after initial startup, conduct, or have conducted, a performance test on each CT and Duct Burner to determine compliance with the emission limits of CO, during operation in non-startup/shutdown mode as defined 15.1.1.e. After the initial tests, subsequent performance testing on CO shall be conducted annually (no more than 14 months following the previous test) unless the previous results demonstrate that the affected units achieved compliance of less than or equal to 75 percent of the applicable emission limits, then the permittee may reduce the frequency of subsequent tests to once every two years (no more than 26 calendar months following the previous test). The permittee shall use the test methods specified in Table 15.3.2.b. unless granted approval in writing by the Director to use an alternative test method in a protocol submitted pursuant to 3.3.1.c.

Table 15.3.2.b.: Combustion Turbine Test Methods

Pollutant	Test Method[(1)]
CO	Method 10B

(1) All test methods refer to those given under 40 CFR 60, Appendix A.

For the purposes of CAM, an exceedance occurs when the performance test results demonstrate that the CO emissions from the oxidation catalyst surpass the CO concentration limits in Condition 15.1.4.a. of this operating permit.

[45CSR§30-5.1.c.; 40 CFR §64.6(c)]

[45CSR13, R13-3493, 4.3.2.]

15.3.3. **NO_X Performance Testing under 40 CFR 60, Subpart KKKK.**

a. The permittee must conduct an initial performance test, as required in 40 CFR §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

1. There are two general methodologies that the permittee may use to conduct the performance tests. For each test run:

i. Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in Appendix A to 40 CFR 60. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in Appendix A to 40 CFR 60, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} \times (NO_X)_c \times Q_{std}}{P}$$

Where:
E = NO_X emission rate, in lb/MWh
1.194×10^{-7} = conversion constant, in lb/dscf-ppm
$(NO_X)_c$ = average NO_X concentration for the run, in ppm
Q_{std} = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR §60.4350(f)(2); or

ii. Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in Appendix A of 40 CFR 60. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in Appendix A of 40 CFR 60 to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in 40 CFR §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

2. Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe

designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

3. Notwithstanding paragraph a.2. of this condition, the permittee may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in Appendix A of 40 CFR 60 if the following conditions are met:

i. The permittee may perform a stratification test for NO_X and diluent pursuant to

a. The procedures specified in section 6.5.6.1(a) through (e) of Appendix A of 40 CFR 75.

ii. Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

a. If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5 ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then the permittee may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

b. For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, the permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

c. For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, the permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1 ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

b. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. The permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The permittee must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

1. If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

2. For combined cycle and combined heat and power turbine systems with supplemental heat (duct burner), the permittee must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

3. If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the permittee chooses to monitor the steam or water to fuel ratio in accordance with 40 CFR §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable 40 CFR §60.4320 NO_X emission limit.

4. Compliance with the applicable emission limit in 40 CFR §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in 40 CFR §60.4320.

5. If the permittee elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR §60.4405) as part of the initial performance test of the affected unit.

6. The ambient temperature must be greater than 0°F during the performance test.

[45CSR16; 40 CFR §60.4400; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.3.4. **Alternative Initial NO_X Performance Testing under 40 CFR 60, Subpart KKKK.** If a NO_X-diluent CEMS is installed and certified in accordance with 40 CFR §60.4345, then the initial performance test required under 40 CFR §60.8 may be performed in the following alternative manner:

a. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

b. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

c. Use the test data both to demonstrate compliance with the applicable NO_X emission limit under 40 CFR §60.4320 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR §60.4335.

d. Compliance with the applicable emission limit in 40 CFR §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

[45CSR16; 40 CFR §60.4405; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.3.5. **Testing Requirements for the Duct Burners under 45CSR2.**

a. At such reasonable times as the Secretary may designate, the owner or operator of any fuel burning unit(s) may be required to conduct or have conducted tests to determine the compliance of such unit(s) with the emission limitations of 15.1.2.g. Such tests shall be conducted in accordance with the appropriate method set forth in Appendix 45-2 to 45CSR2 or other equivalent EPA approved method approved by the Secretary. The Secretary may at his option witness or conduct such tests. Should the Secretary exercise his option to conduct such tests, the operator will provide all necessary sampling connections and sampling ports located in such manner as the Secretary may require, power for test

equipment, and the required safety equipment such as scaffolding, railings and ladders to comply with generally accepted good safety practices.

1. Sufficient information on temperatures, velocities, pressures, weights and dimensional values shall be reported to the Secretary, with such necessary commentary as he may require to allow an accurate evaluation of the reported test results and the conditions under which they were obtained.

b. The Secretary may conduct such other tests as he may deem necessary to evaluate air pollution emissions other than those noted in 45CSR§2-4.1.

[45CSR§§2-8.1.2., and -8.1.3.]

15.4. Recordkeeping Requirements

15.4.1. For the purpose of demonstrating compliance with any visible emissions monitoring required by the Director, the permittee shall maintain records documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s). For an emission unit out of service during the evaluation, the record of observation may note "out of service" (O/S) or equivalent.
[45CSR13, R13-3493, 4.4.2.]

15.4.2. **Recordkeeping Requirements for the Duct Burners under 45CSR2.**

a. The owner or operator shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit as specified in paragraph a.1. of this condition. Such records are to be maintained on-site and made available to the Secretary upon request.

1. For fuel burning unit(s) which burn only pipeline quality natural gas, such records shall include, but not be limited to, the date and time of startup and shutdown, and the quantity of fuel consumed on a monthly basis.

[45CSR§2-8.3.3.; 45CSR§§2A-7.1.a. and -7.1.a.1.]

15.4.3. **General Recordkeeping Requirements under CAM.**

a. The owner or operator shall comply with the recordkeeping requirements specified in 40 CFR §70.6(a)(3)(ii). The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 CFR §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 CFR 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[45CSR§30-5.1.c.; 40 CFR §64.9(b)]

15.5. Reporting Requirements

15.5.1. **Reporting Requirements for Duct Burners under 45CSR2**

The owner or operator of a fuel burning unit(s) subject to this rule shall report to the Secretary any malfunction of such unit or its air pollution control equipment which results in any excess particulate matter emission rate or excess opacity (i.e., emissions exceeding the standards in 45CSR§§2-3 and -4 as provided in one of the following subdivisions:

a. Excess opacity periods meeting the following conditions may be reported on a quarterly basis unless otherwise required by the Secretary:

1. The excess opacity period does not exceed 30 minutes within any 24-hour period; and

2. Excess opacity does not exceed 40%.

b. The owner or operator shall report to the Secretary any malfunction resulting in excess particulate matter or excess opacity, not meeting the criteria set forth in paragraph a. of this condition, by telephone or e-mail by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Secretary within 30 days providing the following information:

1. A detailed explanation of the factors involved or causes of the malfunction;

2. The date and time of duration (with starting and ending times) of the period of excess emissions;

3. An estimate of the mass of excess emissions discharged during the malfunction period;

4. The maximum opacity measured or observed during the malfunction;

5. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and

6. A detailed explanation of the corrective measures or programs that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.]

15.5.2. **40 CFR 60, Subpart KKKK Reporting Requirements**

a. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under 40 CFR 60, Subpart KKKK, the permittee must submit reports

of excess emissions and monitor downtime, in accordance with 40 CFR §60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.
[40 CFR §60.4375(a)]

b. For each affected unit that performs annual performance tests in accordance with 40 CFR §60.4340(a), the permittee must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.
[40 CFR §60.4375(b)]

c. For the purpose of reports required under 40 CFR §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

1. For turbines using continuous emission monitoring, as described in 40 CFR §60.4335(b) and §60.4345:

i. An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in 40 CFR §60.4320. For the purposes of 40 CFR 60, Subpart KKKK, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of 40 CFR 60, Subpart KKKK, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

ii. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee will use this information for compliance purposes.

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

[40 CFR §60.4380(b)]

d. All reports required under 40 CFR §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.
[40 CFR §60.4395]

[45CSR16; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.5.3. **General Reporting Requirements under CAM.**

a. On and after the date specified in 40 CFR §64.7(a) by which the owner or operator must use monitoring that meets the requirements of 40 CFR 64, the owner or operator shall submit monitoring reports to the permitting authority in accordance with 40 CFR §70.6(a)(3)(iii).

b. A report for monitoring under 40 CFR 64 shall include, at a minimum, the information required under 40 CFR §70.6(a)(3)(iii) and the following information, as applicable:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

3. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[45CSR§30-5.1.c.; 40 CFR §64.9(a)]

15.6. Compliance Plan

15.6.1. None

16.0 NPP: Fuel Gas Heaters [emission unit ID(s): FH1 and FH2]

16.1. Limitations and Standards

16.1.1. **Fuel Gas Heaters**

The Fuel Gas Heaters, identified as FH1 and FH2, shall each not exceed an MDHI of 9.90 MMBtu/hr, and shall only be fired by pipeline-quality natural gas, ethane, or some combination thereof. The boilers shall operate in accordance with the following:

a. The maximum emissions from each Fuel Gas Heater shall not exceed the limits given in the following table:

Table 16.1.1.a.: Per-Fuel Gas Heater Emission Limits

Pollutant	lb/hr	ton/year
CO	0.82	3.57
NO_X	0.49	2.13
$PM_{2.5}/PM_{10}/PM$	0.07	0.32
SO_2	0.01	0.03
VOC	0.05	0.23

b. As the annual emission limits given under Table 16.1.1.a. are based on the Fuel Gas Heaters operating 8,760 hours per year, there are no annual restrictions on the fuel combusted or hours of operation for the units.

[45CSR13, R13-3493, 4.1.4.a. and c.]

16.1.2. **45CSR2 – Visible Emissions Monitoring**

a. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than 10 percent opacity based on a six-minute block average.
[45CSR13, R13-3493, 4.1.4.d.; 45CSR§2-3.1.]

b. Compliance with the visible emission requirements of 45CSR§2-3.1. shall be determined in accordance with 40 CFR 60, Appendix A, Method 9 and 45CSR16 or by using measurements from continuous opacity monitoring systems approved by the Secretary. The Secretary may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of 45CSR§2-3.1. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.
[45CSR§2-3.2.]

16.2. Monitoring Requirements

16.2.1. **45CSR2 Visual Emission Monitoring.** At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with 16.1.2.a. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.
[45CSR13, R13-3493, 4.2.7.]

16.3. Testing Requirements

16.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established in the permit and/or applicable regulations.
[45CSR13, R13-3493, 4.3.1.]

16.4. Recordkeeping Requirements

16.4.1. For the purpose of demonstrating compliance with any visible emissions monitoring required by the Director, the permittee shall maintain records documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s). For an emission unit out of service during the evaluation, the record of observation may note "out of service" (O/S) or equivalent.
[45CSR13, R13-3493, 4.4.2.]

16.5. Reporting Requirements

16.5.1. None

16.6. Compliance Plan

16.6.1. None

17.0 NPP: Emergency Generator and Emergency Fire Pump Engine [emission unit ID(s): EG1 and FP1]

17.1. Limitations and Standards

17.1.1. **Emergency Generator and Emergency Fire Pump**

The Emergency Generator and Emergency Fire Pump, identified as EG1 and FP1, respectively, shall meet the following requirements:

a. The Emergency Generator shall not exceed 1,676 HP, shall be fired only with diesel fuel with a maximum sulfur content not to exceed 0.05%, and shall not operate in excess of 100 hours per year during times not defined as emergencies. The Emergency Fire Pump shall not exceed 700 HP, shall be fired only with diesel fuel with a maximum sulfur content not to exceed 0.05%, and shall not operate in excess of 100 hours per year during times not defined as emergencies.

b. The maximum emissions from the Emergency Generator shall not exceed the limits given in the following table:

Table 17.1.1.b.: Emergency Generator Emission Limits

Pollutant	lb/hr	ton/year
CO	12.13	0.61
NO_X	16.45	0.82
PM[(1)]	0.77	0.04
SO_2	3.43	0.17
VOCs	5.60	0.28
HAPs	0.01	0.01

(1) All particulate matter emissions are assumed to be $PM_{2.5}$ or smaller. Includes condensables.

c. The maximum emissions from the Emergency Fire Pump shall not exceed the limits given in the following table:

Table 17.1.1.c.: Emergency Fire Pump Emission Limits

Pollutant	lb/hr	ton/year
CO	5.07	0.25
NO_X	4.29	0.21
PM[(1)]	0.32	0.02
SO_2	1.44	0.07
VOCs	1.46	0.07
HAPs	0.01	0.01

(1) All particulate matter emissions are assumed to be $PM_{2.5}$ or smaller. Includes condensables.

d. **40 CFR 60, Subpart IIII Based Not-to-Exceed (NTE) Standards.** Pursuant to the language given under 40 CFR §60.4205(e), the Emergency Generator and the Emergency Fire Pump are subject to the following NTE Standards:

Table 17.1.1.d.: Subpart IIII NTE Standards

Engine Type	Emission Standards					
	NMHC + NO_X		CO		PM	
	g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr
Emergency Generator	8.0	6.0	4.4	3.3	0.25	0.19
Fire Pump	5.0	3.7	4.4	3.3	0.25	0.19

[45CSR13, R13-3493, 4.1.5.a. to d.]

17.1.2. **40 CFR 60, Subpart IIII**

The Emergency Generator and the Emergency Fire Pump are subject to all applicable requirements under 40 CFR 60, Subpart IIII, including the following:

a. **Emergency Generator (EG1).** Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in 40 CFR §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

1. Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in 40 CFR §§60.4202(a)(1) through (2).

i. For engines with a rated power greater than or equal to 37 kW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR 1039, Appendix I, for all pollutants and the smoke standards as specified in 40 CFR §1039.105 beginning in model year 2007.

[40 CFR §§60.4202(a) and (a)(2)]

2. **Table 17.1.2.a.: Emergency Generator Emission Standards**

Engine	Table 2 to Appendix I of 40 CFR 1039 Tier 2 Emission Standards (g/kW-hr)		
	NO_X + NMHC	**CO**	**PM**
Emergency Generator Rated Power > 560 kW; Starting Model Year 2006	6.4	3.5	0.20

[Table 2 to Appendix I of 40 CFR 1039]

[40 CFR §60.4205(b)]

b. **Emergency Fire Pump (FP1).** Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 to Subpart IIII of 40 CFR 60, for all pollutants.

Table 17.1.2.b.: Emergency Fire Pump (FP1) Emission Standards

Maximum Engine Power	Model Year(s)	Table 4 to Subpart IIII of 40 CFR 60 Emission Standards for Stationary Fire Pump Engines					
		NMHC + NO_X		**CO**		**PM**	
		g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr
$450 \leq kW \leq 560$ $(600 \leq HP \leq 750)$	2009+	4.0	3.0	3.5	2.6	0.20	0.15

[40 CFR §60.4205(c); Table 4 to Subpart IIII of 40 CFR 60]

c. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR §60.4205 over the entire life of the engine.
[40 CFR §60.4206]

d. Owners and operators of stationary CI ICE subject to 40 CFR 60, Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.
[40 CFR §60.4207(b)]

e. For an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, the permittee must install a non-resettable hour meter prior to startup of the engine.
[40 CFR §60.4209(a)]

f. For a stationary CI internal combustion engine subject to the emission standards in 40 CFR 60, Subpart IIII, the permittee must do all of the following, except as permitted under 40 CFR §60.4211(g):

1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

2. Change only those emission-related settings that are permitted by the manufacturer; and

3. Meet the requirements of 40 CFR 1068, as applicable.

[40 CFR §60.4211(a)]

g. For the Emergency Generator and the Emergency Fire Pump, the permittee must comply by purchasing an engine certified to the emission standards in 40 CFR §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR §60.4211(g).
[40 CFR §60.4211(c)]

h. For an emergency stationary ICE, the permittee must operate the emergency stationary ICE according to the requirements in 40 CFR §§60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in 40 CFR §§60.4211(f)(1) through (3), is prohibited. If the permittee does not operate the engine according to the requirements in 40 CFR §§60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and must meet all requirements for non-emergency engines.

1. There is no time limit on the use of emergency stationary ICE in emergency situations.

2. The permittee may operate the emergency stationary ICE for the purpose specified in 40 CFR §60.4211(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR §60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR §60.4211(f)(2).

i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

3. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in 40 CFR §60.4211(f)(2). Except as provided in 40 CFR §60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a

facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

i. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

a. The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

b. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

c. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

d. The power is provided only to the facility itself or to support the local transmission and distribution system.

e. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[40 CFR §60.4211(f)]

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16]

17.1.3. **40 CFR 63, Subpart ZZZZ**
An affected source that meets any of the criteria in 40 CFR §§63.6590(c)(1) through (7) must meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines, or 40 CFR 60, Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under 40 CFR 63.
[45CSR13, R13-3493, 4.1.5.f.; 45CSR34; 40 CFR §§63.6590(c) and (c)(1)]

17.2. Monitoring Requirements

17.2.1. None

17.3. Testing Requirements

17.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established in the permit and/or applicable regulations.
[45CSR13, R13-3493, 4.3.1.]

17.3.2. **40 CFR 60, Subpart IIII – Testing Requirements**

a. If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as follows:

1. For a stationary CI internal combustion engine with a maximum engine power greater than 500 HP, the permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution practice for minimizing emissions. In addition, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after the emission-related settings are changed in a way that is not permitted by the manufacturer. The permittee must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[40 CFR §§60.4211(g) and (g)(3)]

b. Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to 40 CFR 60, Subpart IIII must do so according to 40 CFR §§60.4212(a) through (e).

1. The performance test must be conducted according to the in-use testing procedures in 40 CFR 1039, Subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR 1042, Subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR 1039, Appendix I, or with Tier 2 emission standards in 40 CFR 1042, Appendix I, may follow the testing procedures specified in 40 CFR §60.4213, as appropriate.

2. Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR §1039.101(e) and 40 CFR §1039.102(g)(1), except as specified in 40 CFR §1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR 1039.

3. Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR 1039, Appendix I, or Tier 2 emission standards as described in 40 CFR 1042, Appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$NTE\ requirement\ for\ each\ pollutant = (1.25) \times (STD)$$

Where:
STD = The standard specified for that pollutant in 40 CFR 1039 or 1042, as applicable.

[40 CFR §§60.4212(a) to (c)]

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16]

17.4. Recordkeeping Requirements

17.4.1. 40 CFR 60, Subpart IIII – Recordkeeping Requirements

a. If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in Table 5 to Subpart IIII of 40 CFR 60, if the emergency engine does not meet the standards applicable to the non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16; 40 CFR §60.4214(b)]

17.5. Reporting Requirements

17.5.1. 40 CFR 60, Subpart IIII – Reporting Requirements

a. For an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in 40 CFR §60.4211(f)(3)(i), the permittee must submit an annual report according to the requirements in 40 CFR §§60.4211(d)(1) through (3).

1. The report must contain the following information:

i. Company name and address where the engine is located.

ii. Date of the report and beginning and ending dates of the reporting period.

iii. Engine site rating and model year.

iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

v. Hours spent for operation for the purposes specified in 40 CFR §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR

§60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

2. Annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

3. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to 40 C.F.R. 60, Subpart IIII is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR §60.4. Beginning on February 26, 2025, submit annual report electronically according to 40 CFR §60.4214(g).

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16; 40 CFR §60.4214(d)]

17.6. Compliance Plan

17.6.1. None

18.0 NPP: Storage Tanks [emission unit ID(s): OT1 to OT8, AT1, WS1 to WS4, GT1 to GT4, FT1, and FT2]

18.1. Limitations and Standards

18.1.1. **Storage Tanks**
Tank size and material stored shall be limited as specified in the table titled "Natrium Power Plant" in Section 1.1. of this operating permit.
[45CSR13, R13-3493, 4.1.6.]

18.2. Monitoring Requirements

18.2.1. None

18.3. Testing Requirements

18.3.1. None

18.4. Recordkeeping Requirements

18.4.1. None

18.5. Reporting Requirements

18.5.1. None

18.6. Compliance Plan

18.6.1. None

19.0 NPP: Component Leaks

19.1. Limitations and Standards

19.1.1. **Component Leaks**
The permittee shall mitigate the release of fugitive emissions according to the following requirements:

a. The permittee shall, within 180 days of facility startup, submit a modification or Class II Administrative Update, as applicable pursuant to 45CSR13, to revise the number and type of components (valves, pump seals, connectors, etc.) in gas/vapor service or light liquid service (as applicable) listed in Attachment N of Permit Application R13-3493 or any amendments or revisions submitted thereto if the as-built number of components results in calculated VOC or HAP emissions in excess of those given under Attachment N.

[45CSR13, R13-3493, 4.1.8.]

19.2. Monitoring Requirements

19.2.1. None

19.3. Testing Requirements

19.3.1. None

19.4. Recordkeeping Requirements

19.4.1. None

19.5. Reporting Requirements

19.5.1. None

19.6. Compliance Plan

19.6.1. None

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Thu, Jun 19, 2025 at 8:10 AM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>, DJ Wheeler <dwheeler@trinityconsultants.com>

Hi Sarah,

We will review the draft permit and let you know if we have any comments.

Thank you,

Chris

From: Barron, Sarah K <sarah.k.barron@wv.gov>
Sent: Thursday, June 19, 2025 8:08 AM
To: Hortert, Chris <Chris.Hortert@williams.com>; DJ Wheeler <dwheeler@trinityconsultants.com>
Subject: [EXTERNAL] Re: Title V Pre-Draft Permit; R30-05100142-2025

CAUTION! EXTERNAL SENDER STOP. ASSESS. VERIFY!! If suspicious, STOP and click the Phish Alert Button

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Thu, Jun 19, 2025 at 8:08 AM
To: "Hortert, Chris" <chris.hortert@williams.com>, DJ Wheeler <dwheeler@trinityconsultants.com>

Hi Chris,

I wanted to follow-up and to let you know the current timeline for this permit. If possible, please send me any comments or questions that you have about the pre-draft permit and fact sheet by Monday, June 30th. I'm planning to have the notice of comment period published later that week. You will also have the opportunity to provide comments on the draft permit during the 30-day public comment period after the notice has been published.

Thanks,
- Sarah
[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Pre-Draft Permit; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Mon, Jun 16, 2025 at 6:00 PM
To: "Hortert, Chris" <chris.hortert@williams.com>, DJ Wheeler <dwheeler@trinityconsultants.com>

Chris,

Attached are the Natrium Extraction and Fractionation Processing Plant's pre-draft permit and fact sheet for you to review.

There were several revisions to the operating permit in addition to the inclusion of the CAM requirements, the applicable requirements from Subparts Kc and OOOOb, and the power plant's applicable requirements. To ensure that the operating permit remains up-to-date for the equipment that has not yet been constructed, a requirement was added to report the initial startup of the equipment and to submit an application for a permit modification if any revisions are necessary.

The pre-draft permit/fact sheet may also be revised following the Title V Permitting Program Manager's review.

Please let me know if you have any comments or questions.

Thanks,
- Sarah

--
Sarah Barron
Engineer Trainee
West Virginia Department of Environmental Protection
Division of Air Quality
(304) 414-1915
sarah.k.barron@wv.gov

2 attachments

DPFactSheet R30-05100142-2024.pdf
582K

DPPermit R30-05100142-2024.pdf
1722K

West Virginia Department of Environmental Protection
Division of Air Quality

Fact Sheet

For Draft/Proposed Renewal Permitting Action Under 45CSR30 and Title V of the Clean Air Act

Permit Number: **R30-05100142-2025**
Application Received: **August 19, 2024**
Plant Identification Number: **03-54-051-00142**
Permittee: **Blue Racer Midstream, LLC**
Facility Name: **Natrium Extraction and Fractionation Processing Plant (NEFPP) and Natrium Power Plant (NPP)**
Mailing Address: **14786 Energy Road, Proctor, WV 26055**

Physical Location:	Proctor, Marshall County, West Virginia
UTM Coordinates:	512.1 km Easting • 4,400.8 km Northing • Zone 17
Directions:	The facility is located North of New Martinsville, WV off of State Route 2 at 14786 Energy Road, Proctor, WV 26055

Facility Description

The Natrium Extraction and Fractionation Processing Plant (NEFPP) is a natural gas processing plant with natural gas liquids (NGL) processing capability (utilizing seven permitted cryogenic plants) located approximately four miles northwest of Proctor, Marshall County, WV along the east bank of the Ohio River. The facility has the capability to both process large amounts of raw natural gas (by separating out the liquids, drying it, and removing impurities) and to fractionate NGLs into usable components. NGLs are generally defined to be the lighter liquid components entrained in the gas stream as opposed to "condensate" which is the heavier, pentane plus (C5+) fraction of higher boiling point components that are separated at the well-head under standard conditions. NGLs – both after separation from gas pipelined to the site as well as NGLs sent to the site via pipeline, truck, railcar, or barge – are separated (or "fractionated") into their constituent organic compounds. The compounds ethane, propane, butane, i-butane, and natural gasoline are produced by the fractionation process.

The requirements of the NSR permit R13-3493 (issued: December 15, 2020) have been incorporated into this Title V renewal permit. Under this permit, a nominal 230 MW_e gas-fired combined heat and power plant was permitted to be co-located at the site of the existing NEFPP to provide heat duty and electrical power to the plant. The Natrium Power Plant (NPP) is considered one source with the NEFPP.

SIC: 1321, 4911; NAICS: 211130, 221112

Emissions Summary

Plantwide Emissions Summary [Tons per Year]

Regulated Pollutants	Potential Emissions	2024 Actual Emissions
Carbon Monoxide (CO)	293.86	71.68
Nitrogen Oxides (NO_X)	310.63	57.64
Particulate Matter ($PM_{2.5}$)	110.59	2.85
Particulate Matter (PM_{10})	121.11	4.06
Total Particulate Matter (TSP)	153.28	7.74
Sulfur Dioxide (SO_2)	33.47	0.19
Volatile Organic Compounds (VOC)	309.11	74.18

PM_{10} is a component of TSP.

Hazardous Air Pollutants	Potential Emissions	2024 Actual Emissions
Benzene	0.63	0.05
Ethylbenzene	0.28	None Reported
Formaldehyde	6.36	0.08
Hexane	1.44	0.85
Methanol	8.39	4.32
Toluene	2.01	0.08
Xylene	0.93	0.03
Other HAPs	0.70	None Reported
Total HAPs	20.74	5.41

Some of the above HAPs may be counted as PM or VOCs.

Title V Program Applicability Basis

This facility has the potential to emit 293.86 tpy of Carbon Monoxide, 310.63 tpy of Nitrogen Oxides, 110.59 tpy of Particulate Matter – 2.5 microns, 121.11 tpy of Particulate Matter – 10 microns, and 309.11 tpy of Volatile Organic Compounds. Due to this facility's potential to emit over 100 tons per year of criteria pollutant, Blue Racer Midstream, LLC is required to have an operating permit pursuant to Title V of the Federal Clean Air Act as amended and 45CSR30.

Legal and Factual Basis for Permit Conditions

The State and Federally-enforceable conditions of the Title V Operating Permits are based upon the requirements of the State of West Virginia Operating Permit Rule 45CSR30 for the purposes of Title V of the Federal Clean Air Act and the underlying applicable requirements in other state and federal rules.

This facility has been found to be subject to the following applicable rules:

Federal and State:	45CSR2	Control of Particulate Matter Air Pollution from the Combustion of Fuel in Indirect Heat Exchangers.
	45CSR2A	Testing, Monitoring, Recordkeeping, and Reporting Requirements Under 45CSR2.
	45CSR6	Control of Air Pollution from Combustion of Refuse.
	45CSR10	Control of Air Pollution from the Emission of Sulfur Oxides.
	45CSR11	Standby plans for emergency episodes.
	45CSR13	NSR Permit Requirements.
	45CSR16	Standards of Performance for New Stationary Sources.
	WV Code § 22-5-4 (a) (15)	The Secretary can request any pertinent information such as annual emission inventory reporting.
	45CSR30	Operating Permit Requirements.
	45CSR34	Emission Standards for Hazardous Air Pollutants.
	45CSR40	Control of Ozone Season Nitrogen Oxides Emissions.
	40 C.F.R. Part 60 Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.
	40 C.F.R. Part 60 Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.
	40 C.F.R. Part 60 Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023.
	40 C.F.R. Part 60 Subpart Kc	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After October 4, 2023.
	40 C.F.R. Part 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
	40 C.F.R. Part 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines.
	40 C.F.R. Part 60 Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and On or Before September 18, 2015.
	40 C.F.R. Part 60 Subpart OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015, and On or Before December 6, 2022.

	40 C.F.R. Part 60 Subpart OOOOb	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After December 6, 2022.
	40 C.F.R. Part 61	Asbestos inspection and removal.
	40 C.F.R. Part 63 Subpart HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.
	40 C.F.R. Part 63 Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
	40 C.F.R. Part 64	Compliance Assurance Monitoring.
	40 C.F.R. Part 82 Subpart F	Ozone depleting substances.
State Only:	45CSR4	No objectionable odors.
	45CSR17	To Prevent and Control Particulate Matter Air Pollution from Materials Handling, Preparation, Storage, and other Sources of Fugitive Particulate Matter.

Each State and Federally-enforceable condition of the Title V Operating Permit references the specific relevant requirements of 45CSR30 or the applicable requirement upon which it is based. Any condition of the Title V permit that is enforceable by the State but is not Federally-enforceable is identified in the Title V permit as such.

The Secretary's authority to require standards under 40 C.F.R. Part 60 (NSPS), 40 C.F.R. Part 61 (NESHAPs), and 40 C.F.R. Part 63 (NESHAPs MACT) is provided in West Virginia Code §§ 22-5-1 *et seq.*, 45CSR16, 45CSR34 and 45CSR30.

Active Permits/Consent Orders

Permit or Consent Order Number	Date of Issuance
R13-2896K	August 17, 2023
R13-3493	December 15, 2020

Conditions from this facility's Rule 13 permit(s) governing construction-related specifications and timing requirements will not be included in the Title V Operating Permit but will remain independently enforceable under the applicable Rule 13 permit(s). All other conditions from this facility's Rule 13 permit(s) governing the source's operation and compliance have been incorporated into this Title V permit in accordance with the "General Requirement Comparison Table," which may be downloaded from DAQ's website.

Determinations and Justifications

On December 15, 2020, Blue Racer Midstream, LLC was issued the NSR permit R13-3493 for the construction of a nominal 230 MW_e gas-fired combined heat and power plant to be co-located on the site of the existing Natrium Extraction and Fractionation Processing Plant (NEFPP). The Natrium Power Plant (NPP) is considered “one-source” with the NEFPP. The NPP will provide electrical power and heat duty to the NEFPP.

R13-3493 permits the construction and operation of four combustion turbines (either 482.6-mmBTU/hr or 496.2-mmBTU/hr, depending on the operating scenario selected) each equipped with a 475.1-mmBTU/hr duct burner. The NPP is also permitted to construct and operate two 9.9-mmBTU/hr fuel gas heaters, one 1,676-HP emergency

generator, one 700-HP emergency fire pump engine, four 5,000-gallon lubricating oil tanks, four 250-gallon waste oil tanks, one 60,000-gallon ammonia/urea storage tank, four 250-gallon washout sumps, four 1,000-gallon glycol tanks, and two 25-gallon fuel tanks. The requirements applicable to the NPP have been incorporated into the operating permit under Sections 3.0. and 15.0. through 19.0.

The following changes have been made to the Title V operating permit:

1. The permittee mailing address has been updated to 14786 Energy Road, Proctor, WV 26055.

2. Section 1.0. – Emission Units and Active R13, R14, and R19 Permits

    a. The table containing the emission units permitted under R13-2896K was titled "Natrium Extraction and Fractionation Processing Plant".

    b. A vapor recovery unit (VRU) is used to gather vapors from the natural gasoline storage tanks (TK-802 through TK-6802). The VRU was added to the Emission Unit Table as one of the control devices for these tanks, and a reference to the VRU was added to footnote (3) of the table.

    c. As of the writing of this operating permit, construction of the emission units in Cryogenic Processing Trains 5 to 7 of the NEFPP has not begun. Emission units which have not been constructed include the following:

        i. Regeneration Gas Heaters: S040, S044, S048

        ii. Cryogenic HMO Heaters: S041, S045, S049

        iii. Hot Oil Heaters: S052, S053

        iv. Stabilizer Heater: S056

        v. Natural Gasoline Storage Tanks: TK-3802 through TK-6802

        vi. Refrigerated Propane Storage Tank: TK-7802

        vii. Spherical NGL Storage Tanks: US-2800, US-2801, US-2804, US-2805

        viii. Pressurized NGL Bullet Tanks: V-2905, V-2915, V-2925, V-2935

        ix. Slop Tank: TK-2906

        x. Produced Water Tank: TK-2907

        xi. Ethane Amine Regenerator: S054

        xii. Fugitive Areas: FUG AREA 5 through FUG AREA 7

        The installation year of these units was removed from the operating permit and replaced with "Not Yet Constructed".

    d. Under R13-2896I, the construction and operation of one or more fire pump engines/generators was permitted under the emission unit ID S058. The engine(s) are not to exceed an aggregate mechanical boilerplate rating of 3,000 HP. On September 26, 2023, an initial notification of startup for two 800-HP fire pump engines was submitted. A footnote was added to the emission units table for the NEFPP to note that, as of the writing of this operating permit, emission unit S058 is comprised of these two engines.

    e. The emission units associated with R13-3493 were added under the emission units table titled "Natrium Power Plant". These include four turbines (currently two different sets of turbines are permitted, but only

one will be operated at the facility) equipped with a duct burner, two fuel gas heaters, one emergency generator, one emergency fire pump engine, and a variety of storage tanks. As of the writing of this operating permit, construction of these emission units has not commenced, and the installation year of these units was listed as "Not Yet Constructed".

3. Section 3.0. – Facility-Wide Requirements

   a. The following boilerplate changes have been made to the permit. These changes to the boilerplate became effective September 23, 2024.

      i. The citation of Condition 3.1.6. was revised to refer to the current version of the WV Code.

      ii. The citation of Condition 3.3.1. was revised to refer to the current version of the WV Code.

      iii. The following has been added to Condition 3.3.1.b.: "If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit shall be revised in accordance with 45CSR§30-6.4. or 45CSR§30-6.5., as applicable."

   b. The following requirements were added to Section 3.0. of the operating permit:

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-2896 Condition	R13-3493 Condition
3.1.14.	Only the emission unit/sources identified in the table titled "Natrium Power Plant" in Section 1.1. and sources classified as de minimis sources under Table 45-13B of 45CSR13 are authorized at the NPP by R13-3493.	45CSR13	N/A	4.1.1.
3.1.15.	As of the writing of this operating permit, construction of the equipment in the Cryogenic Plants 5 to 7 of the NEFPP and all of the equipment at the NPP has not begun. To ensure that the applicable requirements included in this operating permit are up-to-date, this condition requires the permittee to submit a notification of initial startup for each emission unit within 30 days and to submit, as necessary, a significant Title V permit modification within 180 days of the actual date of initial startup of the emission units.	45CSR§30-6.5.b. 45CSR13	2.18.	2.18.
3.2.1.	Unless otherwise specified, compliance with the annual emission limits must be based on a rolling twelve-month total.	45CSR13	3.2.1.	3.2.1.
3.2.2.	The maximum design capacity limitations of the emission units under Sections 15.1. to 19.1. of this operating permit (Section 4.1. of R13-3493) must be based on a boilerplate rating or on product literature, manufacturer data, or equivalent documentation that shows that the emission units are limited by design to a throughput/production rate that does not exceed the value specified in Sections 15.1. to 19.1.	45CSR13	N/A	4.2.1.

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-2896 Condition	R13-3493 Condition
3.2.3.	The maximum design heat input (MDHI) limitations under Sections 15.1. to 19.1. of this operating permit (Section 4.1. of R13-3493) must be based on a boilerplate rating or on product literature, manufacturer data, or equivalent documentation that shows that the emission units are limited by design to a MDHI that does not exceed the value specified in Sections 15.1. to 19.1.	45CSR13	N/A	4.2.2.

c. The permit shield in Condition 3.7.2. was updated as follows:

i. The non-applicability determination for 45CSR19 has been updated. 45CSR19 establishes a preconstruction permit program for any area designated nonattainment for any national ambient air quality standard (NAAQS) and applies to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment. Marshall County, WV (where the NEFPP is located) was previously designated as a nonattainment area for sulfur dioxide (2010), but, as the facility-wide potential emissions of SO_2 were below 100 tpy, it was determined that the NEFPP was not classified as a "major stationary source" under 45CSR19.

With 85 FR 67661 (effective November 25, 2020), the EPA approved the request submitted by the State of West Virginia to redesignate Marshall County from nonattainment to attainment of the 2010 SO_2 NAAQS. Therefore, 45CSR19 is currently inapplicable to the facility because Marshall County is not classified as a nonattainment area for any of the NAAQS.

ii. The New Source Performance Standards for electric generating units under 40 C.F.R. Part 60 Subparts TTTT and TTTTa and the Cross State Air Pollution Rule under 40 C.F.R. Part 97 Subparts AAAAA, CCCCC, and GGGGG are not applicable to the facility (as described in Items 7. and 14. of the Non-Applicability Determinations section of this fact sheet). At the request of the permittee, these regulations were added to the permit shield.

4. 45CSR2 Requirements in Section 4.0. – Hot Oil Heaters and Section 5.0. – Cryogenic HMO/Stabilizer Heaters

a. 45CSR2 has been revised since the issuance of the previous operating permit. The following changes were made to Sections 4.0. and 5.0. of this operating permit due to these revisions.

i. In the footnotes to the tables in Conditions 4.1.2. and 5.1.2. and in the authorities of Conditions 4.1.2., 4.1.4.b., 5.1.2., and 5.1.4.b., the references to 45CSR§2-4.1.b. were revised to 45CSR§2-4.1.2.

ii. Conditions 4.1.4.c. and 5.1.4.c. both previously contained the startup, shutdown, and malfunction provisions of 45CSR§2-9.1. This requirement was removed from 45CSR2 and, therefore, Conditions 4.1.4.c. and 5.1.4.c. were removed from the permit.

iii. In Conditions 4.3.1. and 5.3.2., the citations were revised from 45CSR§§2-8.1.b. and -8.1.c. to 45CSR§§2-8.1.2. and -8.1.3.

iv. In Conditions 4.4.1.b. and 5.4.1.b., the citations were revised from 45CSR§2-8.3.c. to 45CSR§2-8.3.3.

b. 45CSR10 has been revised since the issuance of the previous operating permit. In the footnotes to the tables in Conditions 4.1.2. and 5.1.2., the references to 45CSR§10-3.1.e. were revised to 45CSR§10-3.1.5.

5. Section 4.0. – Hot Oil Heaters

a. 40 C.F.R. §60.44b(h) requires that the NO_X emission standards under §60.44b apply at all times including periods of startup, shutdown, or malfunction, and §60.44b(i) requires that compliance with the NO_X emission standards under §60.44b is determined on a 30-day rolling average basis. These requirements are applicable to the hot oil heater S001 and were added as paragraphs a. and b. of Condition 4.2.2. The subsequent paragraphs were relabeled accordingly.

b. 40 C.F.R. §60.48b(e)(1) is applicable to affected facilities which combust coal, wood, or municipal-type solid waste. As the hot oil heater S001 combusts natural gas, this requirement was removed from Condition 4.2.2. of the operating permit. The authority of this condition was updated, and the subsequent paragraphs were relabeled accordingly.

c. Under 40 C.F.R. §§60.48b(g) and (g)(1), the owner/operator of an affected facility that has a heat input of 250 mmBTU/hr or less and an annual capacity factor for natural gas greater than 10 percent must comply with the provisions of §§60.48b(b), (c), (d), (e)(2), (e)(3), and (f). According to the notification of initial startup received May 30, 2013, the hot oil heater has a heat input of 216.7 mmBTU/hr and is estimated to have an annual capacity factor of 50 percent. Therefore, §§60.48b(g) and (g)(1) were added to the operating permit as Condition 4.2.2.g. The provisions of §§60.48b(b) through (f) are included in the operating permit under Conditions 4.1.5.c. and 4.2.2.c. to 4.2.2.f.

d. The requirements of 40 C.F.R. Part 60 Subpart Db used to demonstrate compliance with the NO_X emission standards applicable to the hot oil heater S001 were added to the operating permit under Condition 4.3.2. In accordance with §§60.46b(c) and (e)(4), the owner or operator of an affected facility under Subpart Db that has a heat input capacity of 250 mmBTU/hr or less that combusts natural gas shall, upon request, determine compliance with the NO_X emission standards of §60.44b through a 30-day performance test. Additionally, during periods when performance tests are not requested, the NO_X emissions data collected pursuant to §60.48b(g) must be used to calculate a 30-day rolling average emission rate on a daily basis and to prepare excess emission reports. The initial compliance testing requirements of §60.46b(e)(1) were met and, therefore, were not added to the operating permit.

e. Under 40 C.F.R. §60.45b(k), the owner/operator of an affected facility seeking to demonstrate compliance with the SO_2 emission standards of §60.42b(k)(2) is required to follow the applicable procedures in §60.49b(r); and, under 40 C.F.R. §60.47b(f), the owner/operator of an affected facility that demonstrates compliance under §60.45b(k) is not subject to the emission monitoring requirements under §60.47b(a) if the owner/operator maintains fuel records in accordance with §60.49b(r).

The hot oil heater S001 is subject to the SO_2 emission standards of §60.42b(k)(2) and to the recordkeeping requirements of §60.49b(r). Therefore, citations to §60.45b(k) and §60.47b(f) were added to the authority of Condition 4.4.2.c. which contains the requirements of §60.49b(r).

f. Under 40 C.F.R. §60.49b(o), the permittee is required to maintain the records required under §60.49b for a period of two years. This requirement was added to the operating permit as Condition 4.4.2.d.

g. Condition 4.5.2.a. of R30-05100142-2020 (MM03) contained the reporting requirements of 40 C.F.R. §60.49b(b) which required the permittee to submit the performance test data from the initial performance test and the performance evaluation of the CEMS used to comply with the NO_X emission standards of §60.44b. The WV DAQ received the results of the initial 30-day performance test using the CEMS for the hot oil heater S001 on July 17, 2014 and the results of the relative accuracy test audit (RATA) for the CEMS on

June 24, 2014. Therefore, this reporting requirement has been met, and the provisions of §60.49b(b) were removed from the operating permit.

h. In Condition 4.5.2., the authority of the reporting requirement to submit excess emission reports was corrected from §60.48b(h) to §60.49b(h).

i. The following 40 C.F.R. Part 60 Subpart Db requirements are applicable to the hot oil heater S001 and were added to Condition 4.5.2. of the operating permit:

i. For the purposes of §60.48b(g)(1), excess emissions are defined in §60.49b(h)(4) as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b. This definition was added as paragraph b.

ii. §60.49b(i) requires the owner/operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48b(b) to submit reports containing the information recorded under §60.49b(g) (Condition 4.4.2.b. of the operating permit). §60.49b(i) was added to the operating permit as paragraph d.

iii. Under §60.49b(v), electronic quarterly reports for NO_X may be submitted in lieu of the written reports required by §60.49b(h) or (i). This alternative for submitting reports was added to the operating permit as paragraph e.

iv. Per §60.49b(w), the reporting period for reports required under Subpart Db is each 6 month period. This requirement was added to the operating permit as paragraph f.

6. Section 7.0. – Fire Pumps

a. Condition 7.1.2. contains the hourly and annual emission limits established in Condition 8.1.2. of R13-2896K for the fire pump engines S002 and S003. In the previous operating permit, streamlining language was added as a footnote to specify that the limits for NMHC + NO_X and PM were based on the emission standards of Table 4 to Subpart IIII of Part 60. Therefore, compliance with these emission limits will also demonstrate compliance with the Subpart IIII emission standards for NMHC + NO_X and PM for the 2009+ model year fire pump engines with a maximum engine power between 600 and 750 HP. The CO emission limit was also based on the applicable standards of Table 4 to Subpart IIII. Therefore, a citation for the footnote was added to the limit for CO to reference and streamline the CO emission standard of Table 4 to Subpart IIII.

b. Due to amendments made in 40 C.F.R. Part 60 Subpart IIII, Condition 7.1.6. was updated as follows:

i. In accordance with §60.4211(a), the references to 40 C.F.R. Parts 89 and 94 were removed from paragraph a.3. of the operating permit.

ii. In accordance with §60.4211(f), the references to emergency demand response were removed from Condition 7.1.6.c.

c. In accordance with the amendments to 40 C.F.R. §60.4214(d), Condition 7.5.1. was updated as follows:

i. The applicability of these requirements to engines that are "contractually obligated to be available for more than 15 hours per calendar year" was removed.

ii. Because the provisions of §§60.4211(f)(2)(ii) and (iii) were vacated, references to these requirements were removed from this condition, the corresponding paragraphs a.v. and a.vi. were removed, and the subsequent paragraph was relabeled.

iii. The website address for the EPA's Central Data Exchange (CDX) was updated to *https://cdx.epa.gov/*.

iv. The requirement that annual reports must be submitted electronically in accordance with §60.4214(g) was added to paragraph c. of this condition.

d. The electronic reporting requirements of 40 CFR §60.4214(g) were added to the operating permit as Condition 7.5.2.

7. Section 8.0. was reserved in R30-05100142-2020 (MM01). With this renewal permit, the reserved section was removed from the operating permit, and Sections 9.0. to 15.0. were relabeled Sections 8.0. to 14.0.

8. Section 8.0. – Glycol Dehydration Units

a. The provisions of 40 CFR §63.764(e)(1) contain the criteria for the exemption of an area source subject to 40 C.F.R. Part 63 Subpart HH from the requirements of §63.764(d). These criteria were listed in Condition 9.1.5. of the previous operating permit and Condition 10.1.5. of R13-2896K. The application indicates that the NEFPP has actual average emissions of benzene from the glycol dehydration unit less than 1 tpy and, therefore, meets the exemption criterion of §63.764(e)(1)(ii). For this reason, the criterion of §63.764(e)(1)(i) was removed from Condition 8.1.5. of this operating permit.

b. The following requirements from 40 C.F.R. Part 63 Subpart HH are applicable to the dehydration unit and were added to the operating permit:

Title V Permit Condition	Summary of Condition	Regulatory Citation
8.1.7.	Conditionally requires the permittee to update the major source determination for any source that is determined not to be a major source under Subpart HH but that has actual emissions are greater than 5 tpy for a single HAP or 12.5 tpy for aggregate HAPs.	45CSR34 40 C.F.R. §63.760(c)
8.1.8.	Any affected source must be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions.	45CSR34 40 C.F.R. §63.764(j)
8.5.1.	Area sources that meet the benzene exemption of §63.764(e)(1)(ii) are exempt from the Subpart HH reporting requirements for area sources.	45CSR34 40 C.F.R. §§63.775(c) and (c)(8)

9. Section 9.0. – 40 CFR 60, Subparts Kb and Kc Storage Tanks

a. Under 40 C.F.R. §60.2, construction is defined as the "fabrication, erection, or installation of an affected facility", and commenced means that "the owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification". Based upon these definitions, construction of the natural gasoline storage tanks TK-3802 through TK-6802 and the refrigerated propane storage tank TK-7802 has not commenced.

When TK-3802 through TK-7802 were initially added to the NSR permit and the operating permit, the requirements of 40 C.F.R. Part 60, Subpart Kb were included as the applicable requirements to these tanks. However, since the issuance of these permits, an amended 40 C.F.R. Part 60 Subpart Kb and a new 40 C.F.R. Part 60 Subpart Kc were published in the Federal Register and became effective on October 15, 2024. The

Subpart Kb amendments establish that the rule is applicable to affected facilities which commenced construction after July 23, 1984 and on or before October 4, 2023. The standards of Subpart Kc are applicable to affected facilities which commenced construction after October 4, 2023.

As construction of TK-3802 through TK-7802 will commence after October 4, 2023, the tanks are subject to Subpart Kc, per §60.110c(a). The reference to TK-3802 through TK-7802 was removed from the Subpart Kb requirements in Condition 9.1.4. of the operating permit. Furthermore, TK-802 and TK-2802 were specified after the authority of Conditions 9.1.4., 9.1.5., 9.4.3., and 9.4.4. which contain the applicable requirements of 40 C.F.R. Part 60 Subpart Kb.

b. The 714,000-gallon storage tanks TK-3802 and TK-5802 and the 1,260,000-gallon storage tanks TK-4802 and TK-6802 will be used to store natural gasoline with a true vapor pressure that is less than 11.1 psia, as stored. A natural gas blanket is used to prevent the loss of natural gasoline vapors to the atmosphere as well as to prevent the potential ingress of atmospheric oxygen to the tank and the potential for a negative internal tank pressure to result in a loss of tank integrity. A vapor recovery unit (VRU) will be installed on the tanks to capture working and breathing losses and displaced vapors from the tank. The captured gas is routed to the Hot Oil Heater S001 to be used as a supplemental fuel.

The 4,200,000-gallon storage tank TK-7802 will be used to store propane with a true vapor pressure that is less than 11.1 psia, as stored. Propane product that flashes-off from the storage tank will be captured by a VRU, re-condensed, and routed back to the storage tank.

The storage tanks TK-3802 through TK-7802 are affected facilities under 40 C.F.R. §60.110c(a) for which construction commenced after October 4, 2023, have a capacity greater than 40,000 gallons, and contain a volatile organic liquid (VOL) with a maximum true vapor pressure equal to or greater than 0.5 psia. Therefore, in accordance with §§60.110c(c) and (c)(1), TK-3802 through TK-7802 are subject to the standards in §60.112c and the corresponding requirements in §§60.113c through 60.116c as new sources.

The following Subpart Kc requirements are applicable to TK-3802 through TK-7802 and have been added to Section 9.0. of the operating permit:

Title V Permit Condition	Summary of Condition	Regulatory Citation
9.1.6.	The standards of Subpart Kc apply at all times, including periods of startup, shutdown, and malfunction.	45CSR16 40 C.F.R. §60.110c(g)

Title V Permit Condition	Summary of Condition	Regulatory Citation
	For storage vessels with a capacity greater than or equal to 40,000 gallons containing a VOL that has a maximum true vapor pressure equal to or greater than 0.5 psia but less than 11.1 psia, the permittee may elect to install and operate each storage vessel with either an internal floating roof meeting the requirements of §60.112c(b), an external floating roof meeting the requirements of §60.112c(c), or a closed vent system routed to a control device, fuel gas system, or process as specified in §60.112c(d). **TK-3802 through TK-6802:** The working and breathing losses of natural gas from the natural gasoline storage tanks TK-3802 through TK-6802 will be collected by a VRU and sent via a closed vent system to Hot Oil Heater S001 for use as fuel. Per §60.111c, a "fuel gas system" is the offsite and onsite piping and control system that gathers gaseous streams generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices. Therefore, for TK-3802 through TK-6802, the permittee will install and operate a closed vent system routed to a fuel gas system as specified in 40 CFR §60.112c(d). **TK-7802:** The propane product that flashes-off from the refrigerated propane storage tank TK-7802 will be captured by a VRU, re-condensed, and routed back to the storage tank. Per §60.111c, "routed to a process" means the emissions are conveyed by a closed vent system to any enclosed portion of the process unit where the emissions are recovered. Therefore, for TK-7802, the permittee will install and operate a closed vent system routed to a process as specified in 40 CFR §60.112c(d).	45CSR16 40 C.F.R. §§60.112c(a) and (a)(1)
	Each storage vessel affected facility complying with the closed vent system routed to a control device, fuel gas system, or process provisions in §60.112c(d) or each storage vessel affected facility with a design capacity greater than 1,000,000-gallons containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 1.5 psia must comply with the requirements of §60.112c(e). TK-3802 through TK-7802 are complying with the closed vent system provisions of §60.112c(d). Furthermore, TK-4802, TK-6802, and TK-7802 have a design capacity greater than 1,000,000-gallons. Therefore, these storage tanks are subject to the storage vessel degassing requirements of §60.112c(e).	45CSR16 40 C.F.R. §60.112c(a)(3)
	The permittee must comply with the Subpart Kb monitoring, recordkeeping, and reporting requirements of §60.113c, §60.115c, and §60.116c, respectively.	45CSR16 40 C.F.R. §60.112c(a)(4)

Title V Permit Condition	Summary of Condition	Regulatory Citation
9.1.7.	TK-3802 through TK-6802 will be operated with a closed vent system that routes to a fuel gas system; and TK-7802 will be operated with a closed vent system that routes to a process. Therefore, the design, installation, and operation requirements for a closed vent system routed to a fuel gas system or process were added to the operating permit. NOTE: The provisions of §§60.112c(d)(3), (5), and (7) which apply to control devices and the provision of §60.112c(d)(4) which refers to the alternative means of emission limitation were not included in the operating permit.	45CSR16 40 C.F.R. §§60.112c(d)(1), (d)(2), and (d)(6)
9.1.8.	TK-3802 through TK-7802 meet the specifications of §60.112(a)(3) and, therefore, must meet the storage vessel degassing requirements to remove liquids from the storage vessel as much as practicable and to reduce total VOC emissions by routing emissions to a fuel gas system or process as specified in §60.112c(d)(6).	45CSR16 40 C.F.R. §§60.112c(e), (e)(1), and (e)(2)(iii)
9.2.2.	For storage vessel affected facilities complying with the closed vent system routed to a control device, fuel gas system, or process provisions in §60.112c(d), the permittee must meet the monitoring requirements of §§60.113c(c) and (d). The permittee must conduct monitoring and inspections of the closed vent system as specified in §60.113c(c)(2), repair leaks as specified in §60.113c(c)(3), and determine the maximum true vapor pressure as specified in §60.113c(d). Since a control device as specified in §60.112c(d)(3) will not be used to reduce emissions from the storage tanks, the control device performance testing requirements of §60.113c(c)(1) and the control device monitoring plan requirements of §60.113c(c)(4) were not included in the operating permit.	45CSR16 40 C.F.R. §§60.113c(c), (c)(2), (c)(3), and (d)
9.4.5.	The recordkeeping requirements applicable to storage vessel affected facilities complying with the closed vent system routed to a fuel gas system or process provisions were added to the operating permit. These requirements include: a. Maintain records for at least 5 years, except as otherwise specified; b. Maintain records showing the dimensions and an analysis of the capacity of the storage vessel; c. An exemption from §60.115c(c) which requires a record of the VOL stored to be maintained; d. Maintain the specified records for the closed vent system; and e. Maintain records of standard site procedures used to empty and degas equipment. The recordkeeping requirements of §§60.115c(d)(3)(i) and (ii), (d)(4), and (d)(5) are applicable to storage vessel affected facilities complying with provisions for closed vent systems routed to a control device and were not included in the operating permit.	45CSR16 40 C.F.R. §§60.115c(a), (b), (c)(2), (d), (d)(3), (d)(3)(iii) to (d)(3)(vii), and (e)

Title V Permit Condition	Summary of Condition	Regulatory Citation
9.5.2.	An initial notification must be submitted within 60 days after the storage vessel becomes an affected facility. The information which must be included in notifications for storage vessel affected facilities complying with the closed vent system routed to a fuel gas system or process provisions was added to the operating permit.	45CSR16 40 C.F.R. §§60.116c(a), (a)(1) to (a)(5), (a)(7), and (a)(8)
9.5.3.	The permittee must submit semiannual reports as specified in 40 C.F.R. §§60.116c(c) and (d). The report must contain the information specified in 40 C.F.R. §§60.116c(c)(1) and (c)(8), as applicable. The reporting requirements applicable to storage vessel affected facilities complying with the internal floating roof, external floating roof, or closed vent system routed to a control device provisions were not included in the operating permit.	45CSR16 40 C.F.R. §§60.116c(c), (c)(1), (c)(8), (c)(8)(ii), (c)(8)(iii), (c)(11), (c)(12), and (d)
9.5.4.	Requirements for electronically submitting notifications and reports under 40 C.F.R. Part 60, Subpart Kc.	45CSR16 40 C.F.R. §60.116c(f)

c. The authority of Condition 9.4.4. (previously Condition 10.4.4.) was corrected. Condition 9.4.4. contains the provisions of §§60.116b(a) and (b) which require the permittee to maintain records, for the life of the source, showing the dimension of each storage vessel and an analysis showing the capacity of each storage vessel. The authority of Condition 9.4.4. was corrected from §§60.115b(a) and (b) to §§60.116b(a) and (b).

10. Section 10.0. – Flare

a. 45CSR6 has been revised since the issuance of the previous operating permit. 45CSR§6-8.2., which allowed for variations from the emission standards of 45CSR6 in the event of an equipment malfunction, was removed from the rule. Therefore, these requirements were removed from Condition 10.1.4. of this operating permit.

b. Condition 11.1.8. of the previous operating permit was not included in this renewal permit. This condition required the permittee to comply with the emergency and affirmative defense requirements previously contained in Section 2.17. of the operating permit (Section 2.12. of the NSR permit). However, with the issuance of R13-2896K and R30-05100142-2020 (MM03), the emergency requirements were removed from the boilerplate requirements of NSR and Title V operating permits.

c. **40 C.F.R. Part 64** – *Compliance Assurance Monitoring (CAM)*

The flare S004A meets the CAM applicability criteria of §64.2 for emissions of VOCs:

§64.2(a)(1)
Under Condition 13.1.2.b. of R13-2896K, the flare is subject to an annual emission limit of 39.38 tpy for VOC emissions from the controlled process streams as well as a minimum VOC destruction and removal efficiency of 98%.

§64.2(a)(2)
The flare S004A controls emissions of VOCs and HAPs from sources of waste gas, including pigging, blowdowns, purges from the closed vent system, irregular process vents, and ethane treater (S011, S054) flash tanks.

§64.2(a)(3)
The sources of waste gas collectively have the uncontrolled potential to emit 1,949 tpy of VOCs, which exceeds the Title V major source threshold for criteria pollutants.

Therefore, the sources of waste gas are PSEUs for VOCs. As the post-control device VOC emissions are below the Title V major source thresholds, the sources are considered "other" PSEUs, and the CAM Plan was submitted during this operating permit renewal in accordance with 40 C.F.R. §64.5(b).

The uncontrolled potential emissions of HAPs from pigging, blowdowns, purges from the closed vent system, irregular process vents, and ethane treater (S011, S054) flash tanks do not exceed the Title V major source thresholds. Therefore, the sources of waste gas are not subject to CAM for HAPs per §64.2(a)(3).

To demonstrate compliance with CAM for VOCs, monitoring of the flare will be conducted as follows:

	Indicator No. 1
I. Indicator	Presence of the pilot light flame.
A. Monitoring Approach	A duplex thermocouple or equivalent device is used to detect the presence of a pilot light flame.
II. Indicator Range	An excursion occurs when the pilot light flame is absent. If an excursion occurs, an alarm will alert the facility personnel that the pilot light has been extinguished. Upon confirmation that the pilot light has been extinguished, the facility personnel will reignite the pilot. If the facility personnel are unable to reignite the pilots, further corrective actions will be taken or the associated process units will be shutdown. The occurrence of an excursion will be cause for investigation. Any excursions and corrective actions will be documented and reported.
A. QIP Threshold	A threshold for requiring the implementation of a QIP has not been specified at this time. The requirements for a QIP have been included by reference in Condition 11.2.9. of the operating permit.
III. Performance Criteria	
A. Data Representativeness	The presence or absence of the flare's pilot light flame is monitored by a thermocouple and recorded in the facility's data acquisition system.
B. Verification of Operational Status	Not Applicable. The flare and thermocouple are neither new nor modified.
C. QA/QC Practices and Criteria	The thermocouple will be calibrated annually. A camera mounted near the flare helps to validate data coming from the ground flare HMI.
D. Monitoring Frequency	The thermocouple will continuously monitor and record the presence or absence of the pilot light flame.
E. Data Collection Procedure	The presence or absence of the pilot light flame will be recorded in the facility's data acquisition system at 15-minute intervals.
F. Averaging Period	None.

The following requirements have been added to the operating permit to demonstrate compliance with CAM:

Title V Permit Condition	Summary of Condition	Regulatory Citation
10.2.2.	Condition 13.2.2. of R13-2896K requires the permittee to use a thermocouple to continuously monitor for the presence of the flare's pilot light flame. This condition has been updated to incorporate the CAM Plan into the operating permit as follows: a. The requirement now specifies that a duplex thermocouple or equivalent device is used to detect for the presence of a flame. b. A recordkeeping requirement to record the presence or absence of the flame in the facility's data acquisition system at 15-minute intervals was added. c. An excursion from the CAM Plan has been defined as the absence of the flame.	40 C.F.R. §64.6(c) 45CSR§30-5.1.c. 45CSR13
10.2.4.	The requirements for proper maintenance of monitoring equipment.	40 C.F.R. §64.7(b) 45CSR§30-5.1.c.
10.2.5.	The permittee shall conduct monitoring as required at all times that the PSEU is in operation.	40 C.F.R. §64.7(c) 45CSR§30-5.1.c.
10.2.6.	The requirements for responding to excursions or exceedances.	40 C.F.R. §64.7(d) 45CSR§30-5.1.c.
10.2.7.	The requirements for documentation of need for improved monitoring.	40 C.F.R. §64.7(e) 45CSR§30-5.1.c.
10.2.8.	A QIP may be required based on the determination made under 40 C.F.R. §64.7(d)(2). If required, the QIP must be developed and implemented in accordance with 40 C.F.R. §§64.8(b) through (e).	40 C.F.R. §64.8 45CSR§30-5.1.c.
10.4.2.	The general recordkeeping requirements for CAM.	40 C.F.R. §64.9(b) 45CSR§30-5.1.c.
10.5.4.	The general reporting requirements for CAM.	40 C.F.R. §64.9(a) 45CSR§30-5.1.c.

11. Section 13.0. – Pigging Operations

    a. With the issuance of R13-2896J and R30-05100142-2020 (MM02), the maximum emission limits for pigging operations (except the propane pig trap) (S035) in Condition 14.1.4. (13.1.4. of this renewal permit) were revised. As part of the revisions, new hourly and annual limits were added for these pigging operations, while the previous annual limits were set to expire twelve months after the issuance of R13-2896J (issued: April 5, 2022). These limits are no longer applicable and, therefore, were removed from the operating permit.

    b. In the previous operating permit, the label 14.1.4. was used for two conditions. This was corrected in this renewal permit, and the subsequent conditions were renumbered accordingly.

12. Section 14.0.: 40 CFR 60, Subparts OOOO, OOOOa, and OOOOb Requirements

    a. Under 40 C.F.R. §60.2, construction is defined as the "fabrication, erection, or installation of an affected facility", and commenced means that "an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to

undertake and complete, within a reasonable time, a continuous program of construction or modification". Based upon these definitions, construction of the equipment in the Cryogenic Processing Trains 5 through 7 has not commenced.

The 40 C.F.R. Part 60 Subpart OOOOa equipment leak provisions for process unit equipment and reciprocating compressors were included by reference in the underlying NSR permits R13-2896F and R13-2896G, and these provisions were incorporated into the initial Title V operating permit. However, since the issuance of these permits, an amended 40 C.F.R. Part 60 Subpart OOOOa and a new 40 C.F.R. Part 60 Subpart OOOOb were published in the Federal Register on March 8, 2024 with an effective date of May 7, 2024. The Subpart OOOOa amendments established that the rule was applicable to affected facilities which commenced construction after September 18, 2015 and on or before December 6, 2022. The standards of Subpart OOOOb were applicable to affected facilities which commenced construction after December 6, 2022.

As construction of the Cryogenic Processing Trains 5 through 7 will commence after December 6, 2022, each electric reciprocating compressor affected facility and each process unit equipment affected facility that are part of Cryogenic Processing Trains 5 through 7 will be subject to Subpart OOOOb, per §§60.5365b(c) and (f), respectively. Therefore, the following changes were made throughout Section 14.0. of the operating permit:

i. The references to FUG AREA 5 through 7 were removed from the Subpart OOOOa equipment leak standards for process units. This included revising Condition 14.1.1. of the operating permit (Condition 17.1.1. of R13-2896K) to state that "In accordance with the request given in Permit Application R13-2896K, the permittee shall operate FUG AREA 1 through 4 in accordance with all applicable requirements given under 40 CFR 60, Subpart OOOOa, even those areas that are eligible to comply with 40 CFR 60, Subparts KKK and OOOO."

ii. References to the reciprocating compressor requirements of 40 C.F.R. Part 60 Subpart OOOOb were added to Condition 14.1.5. of the operating permit (previously Condition 15.1.3. of R30-05100142-2020 (MM03); Condition 17.1.2. of R13-2896K). Under this requirement, the permittee is required to maintain an updated list of all reciprocating compressors and the applicability of each to Subparts OOOO, OOOOa, and OOOOb. A citation to 45CSR§30-5.1.c. was added to the authority of this condition.

b. The following Subpart OOOOb requirements for process unit affected facilities are applicable to FUG AREA 5 through 7 and were added to Section 14.0. of the operating permit:

Title V Permit Condition	Summary of Condition	Regulatory Citation
14.1.3.	FUG AREA 5 through 7 will be subject to the Subpart OOOOb provisions for reducing methane and VOC emissions from equipment leaks in process unit equipment. The standards of §60.5400b as well as the alternative standards of §60.5401b were included in the operating permit as Conditions 14.1.3. and 14.1.4., respectively. NOTE: As the facility is a fractionating plant, 40 C.F.R. §§60.5400b(d)(2), 60.5401b(c)(2), and 60.5401b(c)(3), which contain requirements for pressure relief devices located in a nonfractionating plant, were not included in the operating permit.	45CSR16 40 C.F.R. §§60.5400b(a) to (c), (d), (d)(1), (d)(3), and (e) to (l)
14.1.4.		45CSR16 40 C.F.R. §§60.5401b(a) to (c), (c)(1), (c)(4), (c)(5), and (d) to (m)

Title V Permit Condition	Summary of Condition	Regulatory Citation
14.1.11.	The requirements applicable to closed vent systems that are used to comply with the Subpart OOOOb standards for process unit equipment were added to the operating permit in paragraphs a.2. to a.4. and paragraph c. of this condition.	45CSR16 40 C.F.R. §§60.5411b(a)(2) to (a)(4) and (c)
14.2.2.	Exceptions for the GHG and VOC standards for process unit equipment affected facilities. NOTE: §60.5402b(b), which applies to equipment at a nonfrationating plant, and §60.5402b(c), which applies to the components of a process unit located in the Alaskan North Slope, are inapplicable to the facility and were not included in the operating permit.	45CSR16 40 C.F.R. §§60.5402b(a) and (d) to (f)
14.2.3.	Initial compliance demonstration requirements for process unit equipment affected facilities under Subpart OOOOb.	45CSR16 40 C.F.R. §60.5410b(h)
14.2.4.	Continuous compliance demonstration requirements for process unit equipment affected facilities under Subpart OOOOb.	45CSR16 40 C.F.R. §60.5415b(j)
14.2.11.	The additional continuous compliance demonstration requirements in §60.5415b(f) are applicable to process unit equipment that use a control device to meet the relevant Subpart OOOOb standards and were included in this operating permit by reference.	45CSR16 40 C.F.R. §60.5415b(f)
14.2.12.	The continuous monitoring requirements of §60.5417b are applicable to process unit equipment that use a control device to meet the relevant Subpart OOOOb standards and were included in this operating permit by reference.	45CSR16 40 C.F.R. §60.5417b
14.3.6.	The performance testing procedures for control devices which are applicable when a control device is used to demonstrate compliance with the Subpart OOOOb emission standards for process unit affected facilities. These testing procedures were included in the operating permit by reference.	45CSR16 40 C.F.R. §60.5413b
14.3.7.	The requirements for inspections for closed vent systems and bypass devices at process unit equipment affected facilities under Subpart OOOOb were added to the operating permit in paragraphs a., b., and d. of this condition.	45CSR16 40 C.F.R. §60.5416b(a)
14.3.8.	The no identifiable emissions test methods and procedures of Subpart OOOOb were included in the operating permit by reference.	45CSR16 40 C.F.R. §60.5416b(b)
14.4.3.	For process unit equipment affected facilities under Subpart OOOOb, the permittee must maintain records of each equipment leak monitoring inspection and each leak identified.	45CSR16 40 C.F.R. §60.5421b

Title V Permit Condition	Summary of Condition	Regulatory Citation
14.4.7.	For each process unit equipment affected facility subject to Subpart OOOOb, the permittee must maintain the records for closed vent systems, bypass devices, and control devices specified in paragraphs a. and c. to e. of this condition, as applicable. The permittee must also maintain records of each performance test submitted as specified in paragraph f. of this condition. NOTE: The records required by §§60.5420b(c)(11)(i) through (ix) for control devices used to comply with emission reduction standards were included in the operating permit by reference.	45CSR16 40 C.F.R. §§60.5420b(c), (c)(8), and (c)(10) to (c)(13)
14.5.4.	For each process unit equipment affected facility, the permittee must submit the notifications required in §§60.7(a)(1), (3), and (4) and §60.15(d). The permittee must also submit annual reports containing the information specified in paragraphs b.1. to b.5. of this condition, as applicable, as well as semiannual reports for each process unit as specified in paragraph d. of this condition. NOTE: The information specified in §§60.5420b(b)(11)(v)(A) through (P), which must be included in reports when a control device is used to comply with the emissions standard for process unit equipment, was included in the operation permit by reference.	45CSR16 40 C.F.R. §§60.5420b(a), (a)(1), (b), (b)(1), (b)(1)(i) to (iv), (b)(11) to (b)(13), (b)(15), (d) 40 C.F.R. §60.5422b

c. The following Subpart OOOOb requirements for reciprocating compressor affected facilities are applicable to any electric reciprocating compressors used within Cryogenic Processing Trains 5 through 7 and, therefore, were added to Section 14.0. of the operating permit:

Title V Permit Condition	Summary of Condition	Regulatory Citation
14.1.10.	GHG and VOC standards for reciprocating compressor affected facilities subject to Subpart OOOOb. The permittee may demonstrate compliance either by conducting volumetric flow rate measurements (§§60.5385b(a) to (c)), by using a rod packing emissions collection system to route the rod packing emissions to a process (§60.5385b(d)(1)), by reducing emissions from each rod packing emissions collection system by using a control device (§60.5385b(d)(2)), or by periodically replacing the rod packing (§60.5385b(d)(3)). Additionally, the permittee must demonstrate initial and continuous compliance, submit reports, and maintain records as specified in §§60.5385b(e) to (g).	45CSR16 40 C.F.R. §60.5385b
14.1.11.	The requirements applicable to closed vent systems or covers that are used to comply with the Subpart OOOOb standards for reciprocating compressors were added to the operating permit in paragraphs a.1., a.3., a.4., b., and c. of this condition.	45CSR16 40 C.F.R. §§60.5411b(a)(1), (a)(3), (a)(4), (b)(1), (b)(2), (b)(4), and (c)

Title V Permit Condition	Summary of Condition	Regulatory Citation
14.2.9.	Initial compliance demonstration requirements for reciprocating compressors subject to Subpart OOOOb.	45CSR16 40 C.F.R. §60.5410b(e)
14.2.10.	Continuous compliance demonstration requirements for reciprocating compressors subject to Subpart OOOOb.	45CSR16 40 C.F.R. §60.5415b(g)
14.2.11.	The additional continuous compliance demonstration requirements in §60.5415b(f) are applicable to reciprocating compressors that use a control device to meet the relevant Subpart OOOOb standards and were included in this operating permit by reference.	45CSR16 40 C.F.R. §60.5415b(f)
14.2.12.	The continuous monitoring requirements of §60.5417b are applicable to reciprocating compressors that use a control device to meet the relevant Subpart OOOOb standards and were included in this operating permit by reference.	45CSR16 40 C.F.R. §60.5417b
14.3.5.	The test methods and procedures for reciprocating compressor affected facilities which are located at a natural gas processing plant and which demonstrate compliance with the Subpart OOOOb emission standards through §60.5385b(b)(1)(iii). NOTE: §§60.5386b(c)(1) to (7) contains the requirements for the use of a high-volume sampler to measure emissions and were included in the operating permit by reference.	45CSR16 40 C.F.R. §§60.5386b(a), (a)(1), (a)(1)(i), (a)(2), and (b) to (d)
14.3.6.	The performance testing procedures for control devices which are applicable when a control device is used to demonstrate compliance with the Subpart OOOOb emission standards for reciprocating compressor affected facilities. These testing procedures were included in the operating permit by reference.	45CSR16 40 C.F.R. §60.5413b
14.3.7.	The requirements for inspections of closed vent systems, covers, and bypass devices installed at reciprocating compressor affected facilities under Subpart OOOOb were included in paragraphs a. to d. of this condition.	45CSR16 40 C.F.R. §60.5416b(a)
14.3.8.	The no identifiable emissions test methods and procedures of Subpart OOOOb were included in the operating permit by reference.	45CSR16 40 C.F.R. §60.5416b(b)
14.4.6.	The permittee must maintain records for each reciprocating compressor subject to Subpart OOOOb as applicable.	45CSR16 40 C.F.R. §§60.5420b(c) and (c)(5)

Title V Permit Condition	Summary of Condition	Regulatory Citation
14.4.7.	For each reciprocating compressor affected facility subject to Subpart OOOOb, the permittee must maintain the records for closed vent systems, covers, bypass devices, and control devices specified in paragraphs a. to e. of this condition, as applicable. The permittee must also maintain records of each performance test submitted as specified in paragraph f. of this condition. NOTE: The records required by §§60.5420b(c)(11)(i) through (ix) for control devices used to comply with emission reduction standards were included in the operating permit by reference.	45CSR16 40 C.F.R. §§60.5420b(c) and (c)(8) to (c)(13)
14.5.7.	For reciprocating compressor affected facilities subject to Subpart OOOOb, the permittee is not required to submit the notifications required under §§60.7(a)(1), (3), and (4) and §60.15(d). The permittee must submit an annual report containing the information specified in paragraphs b.1. to b.5. of this condition, as applicable. NOTE: The information specified in §§60.5420b(b)(11)(v)(A) through (P), which must be included in reports when a control device is used to comply with the emissions standard for reciprocating compressors, was included in the operation permit by reference.	45CSR16 40 C.F.R. §§60.5420b(a), (a)(1), (b), (b)(1), (b)(1)(i) to (iv), (b)(6), (b)(11), (b)(12), (b)(13), (b)(15), and (d)

d. The requirements of Section 14.0. were renumbered as necessary due to the inclusion of the applicable requirements under Subpart OOOOb.

e. Condition 14.1.2. (previously Condition 15.1.2.) of this operating permit was revised as follows:

   i. 40 C.F.R. §60.5400 has been amended since the issuance of the previous operating permit. A reference to §60.482-1a(e) was added to §60.5400a(a). §60.482-1a(e) excludes equipment designated as being in VOC service less than 300 hr/yr from the requirements of §§60.482-2a through 60.482-10a. The equipment must be identified as required in §60.486a(e)(6) and must meet any of the conditions specified in §§60.482-1a(e)(1) through (3).

   ii. The reference to §60.482-11a was removed from the operating permit. Although a reference to §60.482-11a is included in Subpart OOOOa, the provisions of §60.482-11a were stayed under 73 FR 31376 (effective June 2, 2008) and were removed from Subpart VVa with the amendments established by 89 FR 43070 (effective May 16, 2024).

   iii. The Subpart OOOOa requirements of 40 C.F.R. §§60.5400a(d) to (f) were added to this condition as paragraphs b. through d., respectively. Under these provisions, the permittee is subject to the testing methods of §60.485a, except as provided in §60.5400a(f), as well as the recordkeeping requirements of §60.486a and the reporting requirements of §60.487a, except as provided in §60.5401a, §60.5421a, and §60.5422a.

f. Since the issuance of the previous operating permit, 40 C.F.R. §60.5420a(c)(9) has been reserved. Therefore, the reference to this recordkeeping provision was removed from Condition 14.1.8.d. (previously Condition 15.1.6.d. of R30-05100142-2020 (MM03)).

g. Condition 14.1.9. (previously Condition 15.1.7.) contains the closed vent system requirements of 40 C.F.R. §§60.5411a(a) and (d) which are applicable to each closed vent system used to comply with the emission standards for reciprocating compressors subject to Subpart OOOOa. §60.5411a has been amended since the issuance of the previous operating permit. The following changes have been made to this condition:

   i. Paragraph a. was revised in accordance with the amendments to §60.5411a(a): the references to pneumatic pumps were removed from this paragraph and the requirement now specifies that the closed vent system must be designed to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process.

   ii. The specification that the requirements of §60.5411a(d)(1) apply to storage vessels were revised to include all the affected facilities listed in §60.5411a(d), including reciprocating compressors. Condition 14.1.9.b.1. was updated accordingly.

   iii. §§60.5411a(d)(1), (d)(1)(i), and (d)(1)(ii) have been updated to include that a closed vent system may be certified by either a qualified PE or an in-house engineer. Additionally, the statement "I am aware that there are penalties for knowingly submitting false information," was removed from the required language of the certification.

   Additionally, as the facility does not operate any centrifugal compressors, storage vessels, or pneumatic pumps which are subject to Subpart OOOOa, references to the units were removed from Condition 14.1.9. of the operating permit.

h. 40 C.F.R. §§60.5370(b), 60.5370a(b), and 60.5370b(b) contain the general requirements to maintain and operate any affected facility in a manner consistent with good air pollution control practice for minimizing emissions. These requirements were added to the operating permit as Condition 14.1.13.

i. The provisions of 40 C.F.R. §60.5401a are included in Condition 14.2.1. of this operating permit. These provisions include exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants. The following exceptions were added to the operating permit:

   i. §60.5401a(c) which exempts the sampling connection systems from the requirements of §60.482-5a.

   ii. §60.5401a(f) which provides alternate provisions which may be used for demonstrating that a piece of equipment is in light liquid service or in heavy liquid service.

   iii. §60.5401a(g) which provides alternate provisions for performing calibration drift assessments.

j. In Condition 14.3.3.d. (previously Condition 15.3.3.d.), the reference to §60.5411a(c)(3)(ii) was corrected to §60.5411a(a)(3)(ii).

k. The Subpart OOOOa recordkeeping requirements for reciprocating compressors have been amended since the issuance of the previous permit. These amendments were incorporated into Condition 14.4.5. of the operating permit as follows:

   i. In accordance with §§60.5420a(c)(6)(i) through (iii), the records which must be maintained for each closed vent system inspection were added as paragraphs b.1. through 3. These include records of each closed vent system inspection or no detectable emissions monitoring survey, records of each defect or leak detected, and records for any delay of repair.

   ii. In accordance with §§60.5420a(c)(7)(i) through (iii), the records which must be maintained for each cover inspection were added as paragraphs c.1. through c.3. These include records of each cover inspection, records of each defect detected, and records of any delay of repair.

l. Conditions 14.5.1. through 14.5.3. contain the reporting requirements of §60.5422a which apply to affected facilities subject to the Subpart OOOOa GHG and VOC requirements for onshore natural gas processing plants.

i. With 85 FR 57457 (September 15, 2020), the semiannual reporting requirements referenced in §§60.5422a(a) through (c) were revised.

a. The references to §60.487a(b)(4), which requires the permittee to include the number of compressors subject to §60.482-3a in semiannual reports, were removed from §§60.5422a(a) and (b). §§60.5422a(a) and (b) were amended to specify that the reports must include the information in §§60.487a(b)(1) through (3) and (5).

b. Additionally, the reference to §§60.487a(c)(2)(v) and (vi), which requires the permittee to include information related to leaks from compressors subject to §60.482-3a in semiannual reports, were removed from §60.5422a(c). §60.5422a(c) was amended to specify that the reports must include the information in §§60.487a(c)(2)(i) through (iv) and (vii) through (viii).

ii. Following the finalization of these Subpart OOOOa amendments, the semiannual reporting requirements of §§60.487a(b) and (c) were also amended under 89 FR 43071 (May 16, 2024). The requirements applicable to connectors subject to §60.482-11a were removed from Subpart VVa, including the semiannual reporting requirements of §60.487a(b)(5) as well as §§60.487a(c)(2)(vii) and (viii). Therefore, the references to these provisions were not included in Conditions 14.5.1. to 14.5.3. of the operating permit.

m. The reporting requirements of §60.5420a(b)(4)(iii) are applicable to reciprocating compressors which demonstrate compliance with the Subpart OOOOa emission standards through §60.5385a(a)(3). These provisions were added to the operating permit as Condition 14.5.6.b.3.

n. For each closed vent system routing to a control device or process, the permittee is required to submit the certification signed by the qualified professional engineer or in-house engineer in accordance with §60.5411a(d) and §60.5420a(b)(12). This reporting requirement has been added to the operating permit as Condition 14.5.6.d.

13. Section 15.0. – NPP: Turbines and Duct Burners

Blue Racer Midstream, LLC is currently permitted to construct four combustion turbines (Emission Units: TB1A/B to TB4A/B) for the NPP. Each turbine is associated with a duct burner which will be operated downstream of the turbine.

a. The turbines will be constructed according to one of the following operating scenarios:

i. **Scenario A** is comprised of four General Electric LM6000PG SPRINT combustion turbines (Emission Units: TB1A to TB4A). Each of the turbines is rated at a maximum heat input of 482.6 mmBTU/hr and a maximum power output of 55.275 MW. The turbines are fueled by either ethane or natural gas. The turbines were assumed to operate for 8,760 hours per year, but the time spent in periods of startup and shutdown was limited to 12 hours per year for each mode (Condition 4.1.2.f. of R13-3493). Selective catalytic reduction (SCR1 to SCR4) will be used to control nitrogen oxide (NO_X) emissions, and oxidation catalysts (OC1 to OC4) will be used to control carbon monoxide (CO) and volatile organic compound (VOC) emissions.

ii. **Scenario B** is comprised of four Siemens SGT-800 combustion turbines (Emission Units: TB1B to TB4B). Each of the turbines is rated at a maximum heat input of 496.2 mmBTU/hr and has a maximum

power output of 57.863 MW. The turbines are fueled by either ethane or natural gas. The turbines were assumed to operate for 8,760 hours per year, but the time spent in periods of startup and shutdown was limited to 256 hours per year for each mode (Condition 4.1.2.f. of R13-3493). Selective catalytic reduction (SCR1 to SCR4) will be used to control NO_X emissions, and oxidation catalysts (OC1 to OC4) will be used to control emissions of CO, VOCs, and Formaldehyde.

b. In either operating scenario, a 475.1-mmBTU/hr duct burner will be operated downstream of each turbine. The duct burners are fueled by pipeline-quality natural gas or ethane. Instead of being routed to a heat recovery steam generator (HRSG), the waste heat from the combustion turbines and the heat from the duct burners will be used to generate hot oil to offset the use of the hot oil heaters S016 to S019, S052, and S053 at the existing NEFPP.

Per Condition 4.1.3.f. of R13-3493, the duct burners are limited to the use of 610.81 mmscf of fuel gas per year (approximately 1,745 hours of operation per year). The duct burners are also not to be operated during periods of startup or shutdown for the turbines. The duct burners share the selective catalytic reduction and oxidation catalyst control devices with the associated turbines to reduce emissions of NO_X, CO, and VOCs. The potential emissions of NO_X, CO, and VOCs from the duct burners are based on post-control device emission factors guaranteed by the control device vendors.

c. The turbines are subject to the following regulations:

i. **45CSR13** – *Permits for Construction, Modification, Relocation, and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation*

ii. **45CSR16** – *Standards of Performance for New Stationary Sources*

iii. **40 C.F.R. Part 60 Subpart KKKK** – *Standards of Performance for Stationary Combustion Turbines*

Subpart KKKK establishes emission standards for the control of NO_X and SO_2 from stationary combustion turbines. Construction of the turbines will begin after February 18, 2005, and, for either operating scenario, the turbines will have 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. Therefore, per §60.4305(a), the turbines will be subject to the emission standards, monitoring requirements, recordkeeping requirements, and reporting requirements of Subpart KKKK. The requirements of Subpart KKKK related to demonstrating compliance through the output-based emission standards were not included in the operating permit. A NO_X continuous emissions monitoring system (CEMS) will be installed, operated, and maintained in accordance with §60.4335(b) and §60.4345.

iv. **45CSR40** – *Control of Ozone Season Nitrogen Oxides Emissions*

For either operating scenario, the turbines have a maximum design heat input greater than 250 mmBTU/hr and are not subject to the requirements of the Cross-State Air Pollution Rule (CSAPR). Therefore, per 45CSR§40-4.1., the permittee must comply with the ozone season NO_X emission limitation and monitoring, recordkeeping, and reporting requirements for ozone season emissions of NO_X as established in 45CSR§§40-5 and -6.

v. **40 C.F.R. Part 64** – *Compliance Assurance Monitoring (CAM)*

Because the duct burners are operated with the turbines, the units share control devices, and the units have a common emission point, each turbine and duct burner pair have been considered one emission unit for the purposes of CAM.

a. Under both Scenarios A and B, the turbines and duct burners meet the CAM applicability criteria of 40 C.F.R. §64.2(a) for emissions of CO:

§64.2(a)(1)
The turbines and duct burners as well as the associated oxidation catalysts are subject to emission limits under R13-3493:

1. Conditions 4.1.2.g. and 4.1.3.e. require the permittee to maintain vendor guarantees of the maximum emission rates (ppmvd at 15% O_2) for CO from the turbines and duct burners, respectively.

2. The emission guarantees were used to establish concentration-based limits (ppmvd at 15% O_2) for CO emissions from the oxidation catalysts which control emissions from both the turbines and the duct burners. These limits were established in Condition 4.1.7.a. of R13-3493. The applicable CO emission limit for the turbines are dependent on which operating scenario is selected.

3. Additionally, under Condition 4.1.2.e., the turbines of each scenario are subject to hourly limits for CO emissions during startup, shutdown, and steady-state operations and an annual limit for CO emissions. These emission limits are based on the maximum emissions guarantee from the equipment vendor as well as 8,760 hours of operation per year (the number of hours in each operating mode is determined by the limit for the annual startup/shutdown hours of operation in Condition 4.1.2.f. of R13-3493). Similarly, the duct burners are subject to the hourly and annual CO emission limits under Condition 4.1.3.d., which are based on the equipment vendor's maximum emissions guarantee as well as 1,745 hours of operation per year.

§64.2(a)(2)
In both operating scenarios, the turbines and duct burners use a common oxidation catalyst to reduce emissions of CO.

§64.2(a)(3)

Based on the emission guarantees included in Appendix A: PTE Calculations of this renewal application and the R13-3493 emission limits for the turbines and duct burners, each turbine and duct burner pair has the following uncontrolled potential emissions of CO:

Pre-Control Device CO Emissions

Source	Scenario A [a,c]		Scenario B [b,c]	
	lbs/hr	tpy	lbs/hr	tpy
Turbine – Steady-State	95.8	418	6.1	25.2
Turbine – Startup	153	0.92	51.8	6.6
Turbine – Shutdown	95.8	0.57	12.5	1.6
Duct Burner	106	92.5	106	92.5
Total	--	512	--	125.9

[a] The Scenario A hourly emissions were based on the uncontrolled CO emission guarantees of 94.0 ppmvd for steady-state and shutdown operations and 150.0 ppmvd for startup operations.

The annual emissions from the turbines were based on operation at steady-state for 8,736 hours per year, at startup for 12 hours per year, and at shutdown for 12 hours per year.

[b] The Scenario B hourly emissions were based on the uncontrolled CO emission guarantee of 5.0 ppmvd during steady-state operations and the startup/shutdown CO emission guarantees of 21.6 lbs/startup and 5.2 lbs/shutdown.

The annual emissions from the turbines were based on operation at steady-state for 8,248 hours per year, at startup for 256 hours per year, and at shutdown for 256 hours per year (each startup/shutdown event has an estimated duration of 25 minutes).

[c] The hourly uncontrolled emissions of CO from each duct burner were determined from the post-control device CO potential-to-emit of 2.12 lbs/hr and the 98% control efficiency.

The annual emissions from the duct burners were based on 1,745 hours of operation per year. Operation of the duct burners is not permitted during periods of startup or shutdown of the turbines.

As can be seen in the table above, each turbine and duct burner pair will collectively have pre-control device emissions of CO which exceed the Title V major source thresholds for criteria pollutants.

As the applicability criteria of 40 C.F.R. §64.2(a) are met for emissions of CO, the turbines and duct burners are pollutant-specific emissions units (PSEUs) for CO under CAM. The post-control device CO emissions are below the Title V major source thresholds. Therefore, the turbines are considered "other" PSEUs, and the CAM Plan was submitted during this operating permit renewal in accordance with 40 C.F.R. §64.5(b). The CAM Plan for emissions of CO have been included in this fact sheet under paragraph 13.e.

b. Based on the vendor emission guarantees for the turbines, emissions of VOCs are reduced by the oxidation catalysts in Scenarios A and B, and emissions of Formaldehyde are reduced by the oxidation catalysts in Scenario B. However, the uncontrolled emissions of VOCs and Formaldehyde from the turbines and the duct burners do not exceed the Title V major source thresholds. Therefore, CAM is inapplicable to the turbines and the duct burners for emissions of VOCs and Formaldehyde in accordance with 40 C.F.R. §64.2(a)(3).

c. In both operating scenarios, the turbines are subject to hourly and annual emission limits for NO_X under Condition 15.1.1.e. and concentration-based emission limits for NO_X in Conditions 15.1.1.g. and 15.1.4.a. of the operating permit. Similarly, the duct burners are subject to hourly and annual

emission limits for NO_X under Condition 15.1.2.d. and concentration-based emission limits for NO_X in Conditions 15.1.2.e. and 15.1.4.a. of the operating permit.

These emission limits will be achieved by using SCR, and compliance will be demonstrated with a NO_X CEMS which will be installed, maintained, and operated according to Condition 15.2.7. of the operating permit as well as the provisions of 40 C.F.R. Part 60, Subpart KKKK. Per 40 C.F.R. §§60.4345(b) and 60.4350(b), the CEMS will sample, analyze, and record data for each 15-minute quadrant of an hour. This data will be reduced to the hourly average NO_X emission rate (in ppm) as described in 40 C.F.R. §60.13(h).

In accordance with 40 C.F.R. §64.2(b)(1)(vi), emission limitations for which a part 70 permit specifies a continuous compliance determination method are exempt from the requirements of CAM. 40 C.F.R. §64.1 defines a continuous compliance determination method as a method, which (1) is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation; and (2) provides data either in units of the standard or correlated directly with the compliance limit.

As the CEMS meets the definition of a continuous compliance determination method, CAM is inapplicable to the turbines and duct burners for emissions of NO_X per 40 C.F.R. §64.2(b)(1)(vi).

d. The duct burners are subject to the following regulations:

i. **45CSR2** – *Control of Particulate Matter Air Pollution from the Combustion of Fuel in Indirect Heat Exchangers*

45CSR2 establishes particulate matter emission standards and requirements for fuel burning units. Per 45CSR§2-2.10., a fuel burning unit includes any furnace, boiler apparatus, device, mechanism, stack, or structure used in the process of burning fuel or other combustible material for the primary purpose of producing heat or power by indirect heat transfer. Therefore, the duct burners are subject to the particulate matter emission standards of this rule.

a. The duct burners are subject to the visible emissions standards in 45CSR§2-3. The 10% opacity limit of 45CSR§2-3.1. has been included in the operating permit as Condition 15.1.2.g.1. Compliance with this limit is demonstrated through visible emission checks conducted in accordance with Method 9 of 40 C.F.R. Part 60, Appendix A, as designated by the Secretary (45CSR§2-3.2.; Condition 4.2.7. of R13-3493).

b. The duct burners are also subject to the weight emission standards of 45CSR§2-4. 45CSR§2-4.1. establishes a facility-wide PM emission limit for all non-exempt fuel burning units located at a facility. This includes the hot oil heaters and cryogenic hot medium oil (HMO) heaters of the NEFPP as well as the duct burners at the NPP. All of these units are Type “b” fuel burning units under 45CSR§2-4.1.2., and, therefore, the PM emission limit is the product of 0.09 and the total design heat input for the units, provided that no more than 600 lbs/hr of PM is discharged into the open air from all such units. As can be seen in the table below, the total design capacity of the applicable units is 2,682.84 mmBTU/hr. Therefore, the facility-wide PM emission limit for the Type “b” fuel burning units is 241.46 lbs/hr, per 45CSR§2-4.1.

45CSR§2-4.1.: Facility-Wide PM Emission Limit for Fuel Burning Units				
Emission Unit ID	**Fuel Burning Unit Description**	**Design Capacity (mmBTU/hr)**	**45CSR§2-4.1. PM Limit (lbs/hr)**	**R13-2896K and R13-3493 PM Limits (lbs/hr)**
NEFPP				
S001	Hot Oil Heater	216.7		1.61
S013	Cryogenic HMO Heater	26.3		0.20
S016	Hot Oil Heater	61.58		0.46
S017	Hot Oil Heater	61.58		0.46
S018	Hot Oil Heater	61.58		0.46
S019	Hot Oil Heater	61.58		0.46
S026	Cryogenic HMO Heater	26.3		0.20
S037	Cryogenic HMO Heater	26.3		0.20
S041	Cryogenic HMO Heater	54.67		0.41
S045	Cryogenic HMO Heater	26.3		0.20
S049	Cryogenic HMO Heater	26.3		0.20
S052	Hot Oil Heater	61.58		0.46
S053	Hot Oil Heater	61.58		0.46
S056	Stabilizer Heater	10.09		0.08
NPP				
TB1A/B	Duct Burner #1	475.1		3.65
TB2A/B	Duct Burner #2	475.1		3.65
TB3A/B	Duct Burner #3	475.1		3.65
TB4A/B	Duct Burner #4	475.1		3.65
Totals		**2,682.84**	**241.46**	**20.46**

The PM emission limits established under R13-2896K and R13-3493 are based on the reported PTE of each individual fuel burning unit and show that the fuel burning units collectively have the potential-to-emit PM at a rate of 20.46 lbs/hr. Since this is much less than the PM emission limit established under 45CSR§2-4.1., compliance with 45CSR§2-4.1. will be shown through compliance with the limits of Conditions 4.1.2. (S001, S016-S019, and S052-S053), 5.1.2. (S013, S026, S037, S041, S045, S049, S056), and 15.1.2.d. (TB1A/B-TB4A/B) of this operating permit.

In accordance with 45CSR2 and R13-3493, the provisions of 45CSR§2-4.1. were included in the operating permit under Condition 15.1.2.g.3.

c. Under 45CSR§2-4.4., the addition of sulfur oxides to a combustion exit gas stream for the purpose of improving emissions control equipment efficiency is not allowed unless written approval is provided by the Secretary. This requirement was added to the operating permit as Condition 15.1.2.g.4.

d. The following monitoring, testing, recordkeeping, and reporting requirements of 45CSR2 are applicable to the duct burners:

a. Under 45CSR§2-8.4.2., the owner/operator of a fuel burning unit which combusts only natural gas is exempt from the testing requirements of 45CSR§2-8.1.1. and the monitoring requirements of 45CSR§2-8.2.

b. The testing requirements of 45CSR§§2-8.1.2. and -8.1.3. are applicable to the duct burners. Under these requirements, the permittee may be required to conduct a performance test to demonstrate compliance with the weight emission standards at such reasonable times as the Secretary may designate. These testing requirements were added to the operating permit as Condition 15.3.5.

c. In accordance with the recordkeeping requirements of 45CSR§2-8.3.3. and 45CSR§2A-7.1.a., the permittee must maintain records of the operating schedule and the quantity and quality of the fuel burned in each unit. As the duct burners combust only natural gas/ethane, these records must include the date and time of start-up and shutdown and the quantity of fuel consumed on a monthly basis. The recordkeeping requirements were added to the operating permit under Condition 15.4.2.

e. Condition 4.1.3.g.(3) of R13-3493 contained the provisions of 45CSR§2-9.1. under which the visible emission standards of 45CSR§2-3 were applicable at all times except for periods of startups, shutdowns, and malfunctions. Since the issuance of R13-3493, 45CSR2 was amended to reserve 45CSR§2-9.1. Therefore, this requirement was not included in the operating permit.

f. The permittee is subject to the start-up, shutdown, and malfunction requirements under 45CSR§§2-9.2. and -9.3., which have been added to the operating permit under Condition 15.1.2.g.5. and 15.5.1., respectively.

ii. **45CSR10** –*Control of Air Pollution from the Emission of Sulfur Oxides*

45CSR10 establishes sulfur oxides emission standards and requirements for fuel burning units. Per 45CSR§10-2.8., a fuel burning unit includes any furnace, boiler apparatus, device, mechanism, stack or structure used in the process of burning fuel or other combustible material for the primary purpose of producing heat or power by indirect heat transfer. Therefore, the duct burners are subject to the emission standards of this rule.

a. The duct burners are subject to the weight emission standards of 45CSR§10-3. The facility is located in Marshall County which is classified under Table 45-10A of 45CSR10 as a Priority I Region. All non-exempt fuel burning units located at the facility are subject the facility-wide SO_2 emission limit specified by 45CSR§10-3.1. The applicable units include the hot oil heaters, cryogenic hot medium oil (HMO) heaters, and the stabilizer heater of the NEFPP as well as the duct burners at the NPP, which are all Type "b" fuel burning units under 45CSR§10-2.8. Therefore, in accordance with 45CSR§10-3.1.5., the SO_2 emission limit for these units is the product of 3.1 and the total design heat input of the units. As can be seen in the table below, the total design heat input of the units is 2,682.84 mmBTU/hr. Therefore, the 45CSR§10-3.1. SO_2 emission limit is 8,316.80 lbs/hr.

45CSR§10-3.1.: Facility-Wide SO_2 Emission Limit for Fuel Burning Units				
Emission Unit ID	**Fuel Burning Unit Description**	**Design Capacity (mmBTU/hr)**	**45CSR§10-3.1.5. SO_2 Limit (lbs/hr)**	**R13-2896K and R13-3493 SO_2 Limits (lbs/hr)**
NEFPP				
S001	Hot Oil Heater	216.7		0.15
S013	Cryogenic HMO Heater	26.3		0.02
S016	Hot Oil Heater	61.58		0.04
S017	Hot Oil Heater	61.58		0.04
S018	Hot Oil Heater	61.58		0.04
S019	Hot Oil Heater	61.58		0.04
S026	Cryogenic HMO Heater	26.3		0.02
S037	Cryogenic HMO Heater	26.3		0.02
S041	Cryogenic HMO Heater	54.67		0.04
S045	Cryogenic HMO Heater	26.3		0.02
S049	Cryogenic HMO Heater	26.3		0.02
S052	Hot Oil Heater	61.58		0.04
S053	Hot Oil Heater	61.58		0.04
S056	Stabilizer Heater	10.09		0.01
NPP				
TB1A/B	Duct Burner #1	475.1		0.28
TB2A/B	Duct Burner #2	475.1		0.28
TB3A/B	Duct Burner #3	475.1		0.28
TB4A/B	Duct Burner #4	475.1		0.28
Totals		**2,682.84**	**8,316.80**	**1.66**

The SO_2 emission limits established under R13-2896K or R13-3493 are based on the reported PTE of each individual fuel burning unit and show that the units collectively have the potential to emit SO_2 at a rate of 1.66 lbs/hr. Since the fuel burning units collectively have the potential to emit SO_2 at a rate significantly less than the facility-wide emission limit established by 45CSR§10-3.1.5., compliance with 45CSR§10-3.1. will be shown through compliance with the emission limits of Conditions 4.1.2., 5.1.2., and 15.1.2.d. of this operating permit.

In accordance with 45CSR10 and R13-3493, the provisions of 45CSR§10-3.1. were included in the operating permit under Condition 15.1.2.h.

b. The emission standards of 45CSR§10-4 are applicable to manufacturing process source operations and, therefore, are inapplicable the NEFPP.

c. Condition 4.1.3.h.(2) of R13-3493 includes the requirements of 45CSR§10-5.1. which does not permit the combustion of any refinery process gas stream or any other process gas stream that contains hydrogen sulfide in a concentration greater than 50 grains per 100 cubic feet of gas. However, per Condition 4.1.3.a. of R13-3493, the permittee is required to fuel the duct burners with

only pipeline quality natural gas, ethane, or some combination thereof. As pipeline quality natural gas (which includes ethane) has a maximum sulfur content of 20 grains of hydrogen sulfide per 100 cubic feet, the requirements of 45CSR§10-5.1. have not been included in the operating permit.

d. Per 45CSR§10-10.3., the owners and operators of fuel burning units which combust natural gas are exempt from the testing, monitoring, recordkeeping, and reporting requirements of 45CSR§10-8.

iii. **45CSR13** – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation*

iv. **45CSR16** – *Standards of Performance for New Stationary Sources*

v. **40 C.F.R. Part 60 Subpart KKKK** – *Standards of Performance for Stationary Combustion Turbines*

Subpart KKKK establishes emission standards for the control of NO_X and SO_2 from stationary combustion turbines. Per 40 C.F.R. §60.4305(a), Subpart KKKK is applicable to the emissions from any duct burners associated with turbines that are subject to Subpart KKKK. Thus, the NPP's duct burners are subject to the requirements of Subpart KKKK.

vi. **40 C.F.R. Part 64** – *Compliance Assurance Monitoring (CAM)*

As discussed in paragraph 13.c.v. of this fact sheet, the turbines and duct burners meet the CAM applicability criteria of 40 C.F.R. §64.2(a) for emissions of CO. The CAM Plan for emissions of CO has been included in the following paragraph 13.e.

e. To demonstrate compliance with CAM for CO emissions, monitoring of the turbines, duct burners, and oxidation catalysts will be conducted as follows:

	Indicator No. 1	**Indicator No. 2**
I. Indicator	Performance Testing of CO from the Oxidation Catalyst Outlet	Catalyst Bed Inlet Temperature
A. Monitoring Approach	Performance testing will be conducted periodically to ensure that the CO emission limits of Conditions 15.1.4.a. are met.	The temperature of the catalyst bed inlet will be monitored by a thermocouple.

	Indicator No. 1	**Indicator No. 2**
II. Indicator Range	An exceedance occurs when the performance test results demonstrate that CO emissions from the oxidation catalyst surpass the concentration limits in Condition 15.1.4.a. of the operating permit. If an exceedance occurs, an investigation will be conducted and appropriate corrective actions will be taken. Any exceedances and corrective actions will be documented and reported.	Prior to the initial performance test, an excursion occurs when the inlet temperature is outside of the manufacturer's recommended range. The expected catalyst bed operating temperature is 650°F to 700°F. After the initial performance test, an excursion occurs when the inlet temperature is outside of the range established in the performance test. If an excursion occurs, an investigation will be conducted and appropriate corrective actions will be taken. Any excursions and corrective actions will be documented and reported.
A. QIP Threshold	A threshold for requiring the implementation of a QIP has not been specified at this time. The requirements for a QIP have been included by reference in Condition 15.2.15. of the operating permit.	A threshold for requiring the implementation of a QIP has not been specified at this time. The requirements for a QIP have been included by reference in Condition 15.2.15. of the operating permit.
III. Performance Criteria		
A. Data Representativeness	The performance testing will be conducted in accordance with 40 C.F.R. Part 60, Appendix A, Method 10B.	The catalyst inlet temperature will be monitored by a thermocouple with a minimum accuracy within the range of ±0.01% to ±0.25% of the span.
B. Verification of Operational Status	Not Applicable.	The thermocouple will be installed according to the manufacturer's recommendations.
C. QA/QC Practices and Criteria	The performance testing will be conducted in accordance with 40 C.F.R. Part 60, Appendix A, Method 10B.	The thermocouple will be calibrated annually and in accordance with the manufacturer's recommendations.

	Indicator No. 1	Indicator No. 2
D. Monitoring Frequency	An initial performance test must be conducted within 60 days after achieving the maximum capacity of each combustion turbine/duct burner combination, but no later than 180 days after initial startup. Subsequent performance testing must be conducted annually (no more than 14 months following the previous test). If the previous testing results demonstrate that the PSEU achieved compliance of less than or equal to 75% of the applicable CO emission limits, then the subsequent performance testing may be conducted once every two years (no more than 26 months following the previous test).	The catalyst bed inlet temperature data shall be collected every 24 hours of operation of the turbine and/or duct burner.
E. Data Collection Procedure	Data will be collected in accordance with 40 C.F.R. Part 60, Appendix A, Method 10B.	The temperature data will be recorded in the facility's data acquisition system.
F. Averaging Period	Not Applicable.	None.

f. The following requirements were added to the operating permit and are applicable to the turbines and/or duct burners:

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
15.1.1.	Applicable requirements for the turbines of both operating scenarios. Under R13-3493, the turbines are subject to emission limits for CO, NO_X, PM, SO_2, VOCs, Formaldehyde, and HAPs; limits for the amount of time spent annually in startup and shutdown modes; and a limit for the maximum amount of power that may be supplied by each turbine to the utility distribution systems. The permittee is also required to maintain vendor emission guarantees that the established CO, NO_X, PM, VOCs, and Formaldehyde emission rates from the turbines are achievable.	45CSR13	4.1.2.a. to h.

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
15.1.2.	Applicable requirements for the duct burners. Under R13-3493, the duct burners are subject to a limit for the MDHI; a limit on the type and volume of fuel used; and emission limits for CO, NO_X, PM, SO_2, VOCs, Formaldehyde, and HAPs. The permittee is also required to maintain vendor emission guarantees that the established CO, NO_X, and VOC emission rates from the duct burners are achievable. The duct burners are subject to the visible emission and PM weight emission standards of 45CSR2, as well as the SO_2 weight emission standards of 45CSR10. NOTES: In paragraph 4.1.3.g.(2)(i) of R13-3493, the maximum PM emission limit was mistakenly listed as 1,200 lbs/hr (the maximum PM emission rate for Type "a" fuel burning units) rather than 600 lbs/hr (the maximum PM emission rate for Type "b" fuel burning units). This was corrected in the operating permit. In paragraph 4.1.3.h.(1) of R13-3493, the SO_2 emission standard was mistakenly listed as "the product of 3.2 and the total design heat" rather than "the product of 3.1 and the total design heat". This typo was corrected in the operating permit.	45CSR§§2-3.1., -3.2., -4.1., -4.1.2., -4.4., and -9.2. 45CSR§§10-3.1. and -3.1.5. 45CSR13	4.1.3.a. to h.
15.1.3.	The turbines and associated duct burners are subject to the NO_X and SO_2 emission standards of 40 C.F.R. Part 60 Subpart KKKK.	45CSR13 45CSR16 40 C.F.R. §§60.4320(a), 60.4330(a), and 60.4333(a).	4.1.2.i. and 4.1.3.i.
15.1.4.	The SCR systems and oxidation catalysts which control emissions from the turbines and duct burners are subject the concentration-based emission limits for NO_X, CO, VOCs, and Formaldehyde listed in paragraph a. as well as the operation requirements in paragraphs b. and c. of this condition.	45CSR13	4.1.7.a. to c.
15.1.5.	The turbines are subject to the ozone season NO_X requirements of 45CSR40. The permittee shall install and operate a CEMS to monitor NO_X emissions during the ozone season. The permittee has elected to demonstrate compliance through the operation, monitoring, testing, recordkeeping, and reporting requirements specified in 45CSR§40-6.5.	45CSR§§40-5.1., -6.1., and -6.5.	N/A
15.2.1.	To demonstrate compliance with the maximum startup and shutdown operating hours of Condition 15.1.1.f., the permittee shall monitor and record the total hours each turbine is operated in startup and shutdown modes.	45CSR13	4.2.3.
15.2.2.	To demonstrate compliance with the maximum power export limit of Condition 15.1.1.h., the permittee must monitor and record the monthly and rolling twelve-month total watts exported to the power grid.	45CSR13	4.2.4.

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
15.2.3.	To demonstrate compliance with the duct burner fuel usage limit of Condition 15.1.2.f., the permittee must monitor and record the monthly and rolling twelve-month total volume of fuel used.	45CSR13	4.2.5.
15.2.4.a.	To demonstrate continuous with the hourly, annual, and concentration-based NO_X emission limits for the turbines, duct burners, and SCR system, the permittee must install and operate a NO_X CEMS in accordance with the applicable requirements of 40 C.F.R. Part 60 Subpart KKKK. NOTE: Condition 4.2.6. of R13-3493 specifies that the CEMS shall be installed and operated to demonstrate compliance with the turbines' NO_X emission limits under Table 4.1.2.e. (Condition 15.1.1.e. of the operating permit). As each turbine and duct burner pair will share a common control device, the CEMS will also demonstrate compliance with the hourly and annual emission limits for the duct burners in Condition 4.1.3.d. of R13-3493. Additionally, the turbines, duct burners, and SCR system are subject to concentration-based emission limits under Conditions 4.1.2.g., 4.1.3.e., and 4.1.7. Therefore, a reference to the duct burners' NO_X emission limits in Condition 15.1.2.d. as well as the concentration-based NO_X limits in Conditions 15.1.1.g., 15.1.2.e., and 15.1.4. were added to this requirement in the operating permit.	45CSR13 45CSR§30-5.1.c.	4.2.6.
15.2.4.b.	Emissions of NO_X from each turbine and duct burner pair must be monitored by a CEMS that is installed, certified, maintained, and operated in accordance with the requirements of 40 C.F.R. Part 60 Subpart KKKK.	45CSR13 45CSR16 40 C.F.R. §§60.4335(b) and (b)(1), 60.4340(b) and (b)(1), 60.4345, and 60.4350	4.1.2.i. and 4.1.3.i.
15.2.5.	To demonstrate compliance with the visible emissions requirements of 45CSR2 and Condition 15.1.2.g., Method 9 visible emissions observations shall be conducted at times designated by the Secretary. NOTE: Due to a typo, the incorrect paragraph of Condition 4.1.3. was referenced in Condition 4.2.7. of R13-3493. The 45CSR2 visible emissions monitoring requirements which are applicable to the duct burners are contained in Condition 4.1.3.g. of R13-3493. This typo was corrected in the operating permit.	45CSR13	4.2.7.
15.2.6.	Monitoring, recordkeeping, and reporting requirements for the maintenance of the oxidation catalysts. The permittee must maintain a copy of the site-specific maintenance plan or the manufacturer maintenance plan.	45CSR13	4.2.8.
15.2.7.	Compliance with the 40 C.F.R. Part 60 Subpart KKKK standards for SO_2 will be demonstrated by maintaining a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum total sulfur content for the gaseous fuel is 20 grains of sulfur or less per 100 standard cubic feet.	45CSR13 45CSR16 40 C.F.R. §§60.4365, 60.4365(a), 60.4415(a), and 60.4415(a)(1)	4.1.2.i. and 4.1.3.i.
15.2.8.	To demonstrate compliance with CAM, the catalyst bed inlet temperature shall be monitored by a thermocouple, and the temperature data shall be collected every 24 hours of operation.	45CSR§30-5.1.c. 40 C.F.R. §64.6(c)	N/A

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
15.2.9.	CAM requirements for commencement of operation.	45CSR§30-5.1.c. 40 C.F.R. §64.7(a)	N/A
15.2.10.	CAM requirements for proper maintenance of monitoring equipment.	45CSR§30-5.1.c. 40 C.F.R. §64.7(b)	N/A
15.2.11.	The permittee shall conduct monitoring as required at all times each PSEU is in operation.	45CSR§30-5.1.c. 40 C.F.R. §64.7(c)	N/A
15.2.12.	CAM requirements for the response to excursions or exceedances of monitoring.	45CSR§30-5.1.c. 40 C.F.R. §64.7(d)	N/A
15.2.13.	CAM requirements for documentation of the need for improved monitoring.	45CSR§30-5.1.c. 40 C.F.R. §64.7(e)	N/A
15.2.14.	A QIP may be required based on the determination made under 40 C.F.R. §64.7(d)(2). If required, the QIP must be developed and implemented in accordance with 40 C.F.R. §§64.8(b) through (e).	45CSR§30-5.1.c. 40 C.F.R. §64.8	N/A
15.3.1.	At times designated by the Secretary, the permittee shall conduct testing in accordance with Section 3.3. of the operating permit.	45CSR13	4.3.1.
15.3.2.	Performance testing of NO_X emissions from the turbines and duct burners must be conducted in accordance with the requirements of 40 C.F.R. Part 60 Subpart KKKK. Performance testing of CO emissions from the turbines and duct burners must be conducted in accordance with 40 C.F.R. Part 60, Appendix A, Method 10B. The periodic performance tests will be used as an indicator under the CAM Plan for the oxidation catalysts. After the initial tests, subsequent testing must be conducted on NO_X and CO annually. If the previous performance testing results demonstrate that the affected units achieved compliance of less than or equal to 75% of the applicable emission limits, then the permittee may reduce the frequency of subsequent performance testing to once every two years.	45CSR13 45CSR16 45CSR§30-5.1.c. 40 C.F.R. §60.4340(a) 40 C.F.R. §64.6(c)	4.3.2.
15.3.3.	Requirements for NO_X performance testing under 40 C.F.R. Part 60 Subpart KKKK.	45CSR13 45CSR16 40 C.F.R. §60.4400	4.1.2.i. and 4.1.3.i.
15.3.4.	Alternative requirements under 40 C.F.R. Part 60 Subpart KKKK for the initial NO_X performance test if a NO_X diluent CEMS is installed and certified in accordance with 40 C.F.R. §60.4345.	45CSR16 40 C.F.R. §60.4405	N/A
15.3.5.	45CSR2 testing requirements for visible emissions observations and PM emissions from the duct burners.	45CSR§§2-8.1.2. and -8.1.3.	N/A
15.4.1.	To demonstrate compliance with the required visible emissions monitoring, records of each visible emissions check must be maintained.	45CSR13	4.4.2.

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
15.4.2.	Records of the operation of the duct burners and the quantity and quality of fuel consumed on a monthly basis must be maintained.	45CSR§2-8.3.3. 45CSR§§2A-7.1.a. and -7.1.a.1.	N/A
15.4.3.	General recordkeeping requirements under CAM.	45CSR§30-5.1.c. 40 C.F.R. §64.9(b)	N/A
15.5.1.	The permittee must report any malfunctions of the duct burners or the associated air pollution control equipment which results in excess PM emissions or in excess opacity.	45CSR§2-9.3.	N/A
15.5.2.	Reporting requirements for the turbines and duct burners under 40 C.F.R. Part 60 Subpart KKKK.	45CSR13 45CSR16 40 C.F.R. §§60.4375(a) and (b), 60.4380(b), and 60.4395	4.1.2.i. and 4.1.3.i.
15.5.3.	General reporting requirements for monitoring under CAM.	45CSR§30-5.1.c. 40 C.F.R. §64.9(a)	N/A

14. Section 16.0. – NPP: Fuel Gas Heaters

The NPP also operates two 9.9-mmBTU/hr fuel gas heaters (Emission Units: FH1 and FH2) to control the temperature of the turbine fuel streams. The heaters are fueled by natural gas.

a. The fuel gas heaters are subject to the following regulations:

i. **45CSR2** –*Control of Particulate Matter Air Pollution from the Combustion of Fuel in Indirect Heat Exchangers*

45CSR2 establishes particulate matter emission standards and requirements for fuel burning units. Per 45CSR§2-2.10., a fuel burning unit includes any furnace, boiler apparatus, device, mechanism, stack, or structure used in the process of burning fuel or other combustible material for the primary purpose of producing heat or power by indirect heat transfer. Therefore, the fuel gas heaters are subject to the particulate matter emission standards of this rule.

The fuel gas heaters are subject to the visible emissions standards in 45CSR§2-3. The 10% opacity limit of 45CSR§2-3.1. has been included in the operating permit as Condition 16.1.2.a. Compliance with this limit is demonstrated through visible emission checks conducted in accordance with Method 9 of 40 CFR Part 60, Appendix A (45CSR§2-3.2. and Condition 4.2.7. of R13-3493).

As each of the fuel gas heaters are limited to a design heat input less than 10 mmBTU/hr, the permittee is exempt from the weight emission standards of Section 4; the fugitive emissions control standards of Section 5; the registration standards of Section 6; the testing monitoring, recordkeeping, and reporting requirements of Section 8; and the start-up, shutdown, and malfunction requirements of Section 9 of this rule per 45CSR§2-11.1.

ii. **45CSR10** – *Control of Air Pollution from the Emission of Sulfur Oxides*

45CSR10 establishes sulfur oxides emission standards and requirements for fuel burning units. Per 45CSR§10-2.8., a fuel burning unit includes any furnace used in the process of burning fuel or other

combustible material for the primary purpose of producing heat or power by indirect heat transfer. Therefore, the fuel gas heaters are subject to the emission standards of this rule.

However, per 45CSR§10-10.1., fuel burning units with a design heat input of less than 10 mmBTU/hr are exempt from the weight emission standards of Section 3; the permit requirements of Section 7; and the testing, monitoring, recordkeeping, and reporting requirements of Section 8. Furthermore, 45CSR§10-4.1., which establishes SO_2 emission standards for manufacturing process source operations, is inapplicable because the fuel gas heaters are not part of a manufacturing process; and 45CSR§10-5.1., which limits the concentration of hydrogen sulfide to 50 grains per 100 cubic feet of gas in any refinery or process gas stream that is combusted, is inapplicable because the fuel gas heaters are only fueled by pipeline-quality natural gas (which includes ethane and has a maximum sulfur content of 20 grains of hydrogen sulfide per 100 cubic feet).

Therefore, although the fuel gas heaters are subject to 45CSR10, the emission units currently have no applicable requirements under this rule.

iii. **45CSR13** – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation*

b. The following requirements were added to the operating permit for the fuel gas heaters:

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
16.1.1.	Under R13-3493, the fuel gas heaters are subject to emission limits for CO, NO_X, PM, SO_2, and VOCs. As the annual emission limits are based on 8,760 hours of operation, there are no annual restrictions on the fuel combusted or the hours of operation of the units.	45CSR13	4.1.4.a. and 4.1.4.c.
16.1.2.	The fuel gas heaters are subject to the visible emission limitations under 45CSR2. Compliance with this limit shall be determined in accordance with 40 C.F.R. Part 60, Appendix A, Method 9.	45CSR§§2-3.1. and -3.2. 45CSR13	4.1.4.d.
16.2.1.	Method 9 visible emissions observations shall be conducted at times designated by the Secretary.	45CSR13	4.2.7.
16.3.1.	At times designated by the Secretary, the permittee shall conduct testing of the emission limitations in Condition 16.1.1.a.	45CSR13	4.3.1.
16.4.1.	Compliance with visible emissions monitoring shall be demonstrated by maintaining records of each visible emissions check.	45CSR13	4.4.2.

15. Section 17.0. – NPP: Emergency Generator and Emergency Fire Pump Engine

One 1,676-HP emergency generator (Emission Unit: EG1) and one 700-HP emergency fire pump engine (Emission Unit: FP1) will be operated at the NPP to supply electricity in the event of an emergency. Both of the engines are compression ignition (CI) internal combustion engines (ICE) that combust diesel fuel. At the time of writing this permit, construction of the engines has not commenced.

a. The emergency generator and the fire pump engine are subject to the following regulations:

i. **45CSR13** – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation*

ii. **45CSR16** – *Standards of Performance for New Stationary Sources*

iii. **40 C.F.R. Part 60 Subpart IIII** – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

As construction of the emergency generator will commence after July 11, 2005 and the manufacture date of the engine will be after April 2, 2006, EG1 is subject to the standards of Subpart IIII per §§60.4200(a)(2) and (a)(2)(i). The emergency generator will be a model year 2007 and later emergency stationary CI ICE with a rating of 1,676 HP and a displacement of less than 10 liters per cylinder. Therefore, the engine is subject to the Tier 2 emission standards for NO_X + NMHC, CO, and PM in Appendix I to 40 C.F.R. Part 1039 and to smoke opacity standards of 40 C.F.R. §1039.105. The engine must also be installed with a non-resettable hour meter.

As construction of the emergency fire pump will commence after July 11, 2005 and the manufacture date of the engine will be after July 1, 2006, FP1 is subject to the standards of Subpart IIII per §§60.4200(a)(2) and (a)(2)(ii). The emergency fire pump will be a CI ICE with a rating of 700 HP and a displacement of less than 10 liters per cylinder. Therefore, the engine is subject to the emission standards for NO_X, CO, and PM in Table 4 to Subpart IIII. The engine must be installed with a non-resettable hour meter.

iv. **45CSR34** – *Emission Standards for Hazardous Air Pollutants*

v. **40 C.F.R. Part 63 Subpart ZZZZ** – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

In accordance with §63.6590(a)(2)(iii), the emergency generator and the fire pump engine are classified as new stationary RICEs as construction of the engines commenced after June 12, 2006 and the facility is an area source of HAPs. Per §§63.6590(c) and (c)(1), these engines demonstrate compliance with the requirements of Subpart ZZZZ through compliance with the requirements of 40 C.F.R. Part 60 Subpart IIII.

b. The following requirements are applicable to the emergency generator and the fire pump engine and have been added to Section 17.0. of the operating permit:

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
17.1.1.	Under R13-3493, the emergency generator and the emergency fire pump are subject to limits for the maximum engine power; the type of fuel used; the annual hours of operation; emissions of CO, NO_X, PM, SO_2, VOCs, and HAPs; and the Subpart IIII not-to-exceed standards which the engines' PTE was based on.	45CSR13	4.1.5.a. to 4.1.5.d.

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
17.1.2.	The standards of 40 C.F.R. Part 60 Subpart IIII are applicable to the emergency generator (EG1) and the emergency fire pump (FP1), per §§60.4200(a)(2) and (a)(2)(i).	45CSR13 45CSR16	4.1.5.e.
	<u>Emergency Generator</u>: Under §60.4205(b), owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202. EG1 will be a model year 2007 and later emergency stationary CI ICE with a displacement of less than 10 liters per cylinder and a rating of 1,676 HP. Therefore, in accordance with §60.4202(a)(2), EG1 is subject to the Tier 2 emission standards for NO_X + NMHC, CO, and PM of Table 2 to Appendix I of 40 C.F.R. Part 1039 and the opacity standards specified in 40 C.F.R. §1039.105(b), as applicable.	40 C.F.R. §§60.4202(a)(2) and 60.4205(b) Table 2 to Appendix I of 40 C.F.R. Part 1039 40 C.F.R. §1039.105(b)	
	<u>Emergency Fire Pump</u>: As a fire pump engine with a displacement of less than 30 liters per cylinder, the emergency fire pump is subject to the NMHC + NO_X, CO, and PM emission standards for 2009 model year and later engines with a rating greater than or equal to 450 kW and less than or equal to 560 kW in Table 4 to Subpart IIII of 40 C.F.R. Part 60.	40 C.F.R. §60.4205(c) Table 4 to Subpart IIII of 40 C.F.R. Part 60	
	Both engines are subject to the fuel requirements for diesel-fueled engines with a displacement less than 30 liters per cylinder, must be installed with a non-resettable hour meter, and the compliance demonstration requirements for stationary CI ICEs and emergency engines.	40 C.F.R. §§60.4206; 60.4207(b); 60.4209(a); and 60.4211(a), (c), and (f)	
17.1.3.	As new stationary RICEs located at an area source of HAPs, the emergency generator and the emergency fire pump must meet the requirements of 40 C.F.R. Part 63 Subpart ZZZZ through the requirements of 40 C.F.R. Part 60 Subpart IIII.	45CSR13 45CSR34 40 C.F.R. §§63.6590(c) and (c)(1)	4.1.5.f.
17.3.1.	At times designated by the Secretary, the permittee shall conduct testing of the emission limitations in Conditions 17.1.1.b. and 17.1.1.c.	45CSR13	4.3.1.

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
17.3.2.	For a stationary CI ICE with a maximum rating greater than 500 HP that is not installed, configured, operated and maintained according to the manufacturer's emission-related instructions, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within one year of startup and must conduct subsequent performance testing every 8,760 hours of operation or every three years.	45CSR13 45CSR16 40 C.F.R. §§60.4211(g) and (g)(3) and 60.4212(a) to (c)	4.1.5.e.
17.4.1.	The emergency generator and emergency fire pump are subject to the Subpart IIII requirements to record the time of operation of the engines and the reason the engine was in operation during that time.	45CSR13 45CSR16 40 C.F.R. §60.4214(b)	4.1.5.e.
17.5.1.	For an emergency CI ICE with a maximum engine power of more than 100 HP that operates as specified in §60.4211(f)(3)(i), the permittee must submit an annual report as specified in §60.4214(d).	45CSR13 45CSR16 40 C.F.R. §60.4214(d)	4.1.5.e.

16. Section 18.0. – NPP: Storage Tanks

The power plant will also operate several storage tanks: four 5,000-gallon lubricating oil tanks (OT1 to OT4), four 250-gallon waste oil tanks (OT5 to OT8), one 60,000-gallon ammonia/urea storage tank (AT1), four 250-gallon washout sumps (WS1 to WS4), four 1,000-gallon glycol tanks (GT1 to GT4), one 25-gallon fuel tank for the emergency generator (FT1), and one 25-gallon fuel tank for the emergency fire pump (FT2).

a. The storage tanks are subject to the following regulation:

i. **45CSR13** – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation*

The potential emissions from each of the storage tanks are minimal. However, the design capacity and material stored in the tanks is limited under R13-3493.

b. **40 C.F.R. Part 60 Subpart Kc** – *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After October 4, 2023* – In accordance with §60.110c(a), Subpart Kc is applicable to each storage vessel with a capacity greater than or equal to 20,000 gallons that is used to store volatile organic liquids for which construction commenced after October 4, 2023. With the exception of the ammonia storage tank (AT1), the NPP's storage tanks (OT1 to OT8, WS1 to WS4, GT1 to GT4, FT1, and FT2) do not have a design capacity greater than 20,000 gallons. The design capacity of AT1 is greater than 20,000 gallons, but the tank does not store a volatile organic liquid. Therefore, the NPP's storage tanks are not subject to Subpart Kc.

c. The storage tanks are subject to the following requirements:

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
8.1.6.	The storage tanks operated at the NPP are limited to the tank size and the material stored listed in the Emission Units Table.	45CSR13	4.1.6.

17. Section 19.0. – NPP: Component Leaks

The uncontrolled emissions of VOCs and HAPs from equipment leaks at the NPP were based on emission factors taken from the document EPA-453/R-95-017 – "Protocol for Equipment Leak Emission Estimates." Emission factors were taken from Table 2-4: "Oil and Gas Production Operations Average Emission Factors (kg/hr/source)." As stated in the document, the average emission factor approach is one accepted approach for estimating emissions from components in service within the oil and gas industry. This method is most effective when used for estimating emissions from a population of equipment. The component counts were based on the estimated maximum counts.

a. Equipment leaks from the NPP are subject to the following regulation:

i. **45CSR13** – *Permits for Construction, Modification, Relocation, and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation*

b. The equipment leaks are subject to the following requirements:

Title V Permit Condition	Summary of Condition	Regulatory Citation	R13-3493 Condition
19.1.1.	Within 180 days of the NPP's startup, the permittee must submit a permit revision to revise the number and type of components in gas/vapor service or light liquid service if the as-built number of components results in calculated VOC or HAP emissions in excess of those given in Attachment N of Permit Application R13-3493.	45CSR13	4.1.8.

Non-Applicability Determinations

The following requirements have been determined not to be applicable to the subject facility due to the following:

1. **45CSR19** – *Permits for Construction and Major Modification of Major Stationary Sources Which Cause or Contribute to Nonattainment Areas* – This rule establishes a preconstruction permit program for any area designated nonattainment for any national ambient air quality standard (NAAQS) and applies to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment. Marshall County is currently designated as in attainment for the NAAQS. Therefore, 45CSR19 is inapplicable.

2. **45CSR27** – *To Prevent and Control the Emissions of Toxic Air Pollutants* – Natural gas is included as a petroleum product and contains less than 5% benzene by weight. 45CSR§27-2.4. exempts equipment "used in the

production and distribution of petroleum products providing that such equipment does not produce or contact materials containing more than 5% benzene by weight."

3. **45CSR43** – *Cross-State Air Pollution Rule to Control Annual Nitrogen Oxides Emissions, Annual Sulfur Dioxide Emissions, and Ozone Season Nitrogen Oxides Emissions* – This rule adopts the federal Cross-State Air Pollution Rule (CSAPR) to limit the interstate transport of emissions of NO_X and SO_2 through emissions trading programs under 40 C.F.R. Part 97 Subparts AAAAA, CCCCC, and EEEEE. The turbines TB1A/B through TB4A/B do not qualify as units subject to these rules, and, therefore, 45CSR43 is inapplicable.

4. **40 C.F.R. Part 60 Subpart Da** – *Standards of Performance for Electric Utility Steam Generating Units* – In accordance with §60.4305(a), the turbines and duct burners (TB1A/B to TB4A/B) are subject to 40 C.F.R. Part 60 Subpart KKKK. Therefore, per §60.40Da(e)(1) and §60.4305(b), the provisions of Subpart Da are inapplicable to TB1A/B through TB4A/B.

5. **40 C.F.R. Part 60 Subpart GG** – *Standards of Performance for Stationary Gas Turbines* – In accordance with §60.4305(a), the turbines TB1A/B to TB4A/B are subject to 40 C.F.R. Part 60 Subpart KKKK. Therefore, per §60.4305(b), the turbines are exempt from the provisions of Subpart GG.

6. **40 C.F.R. Part 60 Subparts TTTT and TTTTa** – *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units* – Per §60.5509(b)(3) and §60.5509a(b)(3), an electric generating unit is not subject to Subpart TTTT or TTTTa if the unit is a combined heat and power unit subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater. Under Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of the operating permit), the amount of power supplied by each turbine to the utility distribution systems is limited to 219,000 MWh per year. Therefore, per §60.5509(b)(3) and §60.5509a(b)(3), the turbines are not subject to Subparts TTTT and TTTTa.

7. **40 C.F.R. Part 63 Subpart HH** – *National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities* – The facility is not subject to the equipment leak standards under 40 C.F.R. §63.769 because it is an area source of HAPs, which limits applicability under Subpart HH to only the (TEG) dehydration unit according to 40 C.F.R. §63.760(b)(2).

8. **40 C.F.R. Part 63 Subpart YYYY** – *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* – Per §63.6085, this subpart applies to stationary combustion turbines located at a major source of HAP emissions. As the facility is an area source of HAP emissions, this subpart is inapplicable.

9. **40 C.F.R. Part 63 Subpart DDDDD** – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* – In accordance with 40 C.F.R. §63.7480, this subpart does not apply to the facility since it is not a major source of HAPs as defined in 40 C.F.R. §63.7575.

10. **40 C.F.R. Part 63 Subpart UUUUU** – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* – Per §63.9980, Subpart UUUUU applies to coal- or oil-fired electric utility steam generating units as defined in §63.10042. The turbines located at the NPP are required under Condition 4.1.2.b. of R13-3493 (Condition 15.1.1.b. of this operating permit) to combust pipeline-quality natural gas, ethane, or some combination thereof. Therefore, Subpart UUUUU is inapplicable to the facility.

11. **40 C.F.R. Part 63 Subpart JJJJJJ** – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources* – This subpart does not apply to the facility since the heaters are fueled by natural gas, and gas-fired boilers are exempt per 40 C.F.R. §63.11195(e).

12. **40 C.F.R. Part 72 Subpart A** – *Acid Rain Program General Provisions* – In accordance with 40 C.F.R. §72.6(b)(4)(ii), units that are not affected units subject to the requirements of the Acid Rain Program include units

located at a cogeneration facility for which construction commenced after November 15, 1990 and which supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWh actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis). Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of this operating permit) limits the amount of power supplied by each of the turbines TB1A/B through TB4A/B to the utility power distribution systems to be less than 219,000 MW-hours per year. Therefore, the turbines TB1A/B through TB4A/B are not subject to the requirements of the Acid Rain Program.

13. **40 C.F.R. Part 97 Subpart AAAAA/CCCCC/GGGGG** – *CSAPR NO_X Annual Trading Program/CSAPR SO_2 Group 1 Trading Program/CSAPR NO_X Ozone Season Group 3 Trading Program* – In accordance with §52.38(a)(2)(i) and §52.39(b), the provisions of 40 CFR Part 97 Subparts AAAAA and CCCCC are applicable to sources located in West Virginia with regard to emissions occurring in 2015 and each subsequent year; similarly, in accordance with §52.38(b)(2)(iii)(A), the provisions of 40 C.F.R. Part 97 Subpart GGGGG are applicable to sources located in West Virginia with regard to emissions occurring in 2021 and each subsequent year. Per the applicability criteria of §97.404(a)(1), §97.604(a)(1), and §97.1004(a)(1), the sources considered to be subject to the CSAPR include any stationary fossil fuel-fired boiler or stationary, fossil fuel-fired combustion turbine serving, at any time on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale. However, §97.404(b)(1)(i), §97.604(b)(1)(i), and §97.1004(b)(1)(i) exempt any unit that otherwise qualifies as a source subject to the CSAPR from Subparts AAAAA, CCCCC, and GGGGG, respectively, if the unit also qualifies as a cogeneration unit throughout the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year after such 12-month period and that does not supply in any calendar year more than one-third of its potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. The turbines TB1A/B through TB4A/B are cogeneration units which produce heat and electricity for use at the facility and, under Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of this operating permit), are subject to a federally enforceable limit that restricts the maximum amount of power supplied by each turbine to the utility distribution system to less than 219,000 MWh per year. Therefore, the facility is not subject to the CSAPR NO_X Trading Program, the CSAPR SO_2 Group 1 Trading Program, nor the CSAPR NO_X Ozone Season Group 3 Trading Program, in accordance with §97.404(b)(1)(i), §97.604(b)(1)(i) and §97.1004(b)(1)(i), respectively.

Request for Variances or Alternatives
None.

Insignificant Activities
Insignificant emission unit(s) and activities are identified in the Title V application.

Comment Period
Beginning Date:
Ending Date:

Point of Contact
All written comments should be addressed to the following individual and office:

Sarah Barron
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304
304/414-1915
sarah.k.barron@wv.gov

Procedure for Requesting Public Hearing

During the public comment period, any interested person may submit written comments on the draft permit and may request a public hearing, if no public hearing has already been scheduled. A request for public hearing shall be in writing and shall state the nature of the issues proposed to be raised in the hearing. The Secretary shall grant such a request for a hearing if he/she concludes that a public hearing is appropriate. Any public hearing shall be held in the general area in which the facility is located.

Response to Comments (Statement of Basis)

Not applicable.

West Virginia Department of Environmental Protection

Harold D. Ward
Cabinet Secretary

Permit to Operate

Pursuant to
Title V
of the Clean Air Act

Issued to:

Blue Racer Midstream, LLC
Natrium Extraction and Fractionation Processing Plant (NEFPP) and Natrium Power Plant (NPP)
R30-05100142-2025

Laura M. Crowder
Director, Division of Air Quality

Issued: [Date of issuance] • Effective: [Equals issue date plus two weeks]
Expiration: [5 years after issuance date] • Renewal Application Due: [6 months prior to expiration]

Permit Number: **R30-05100142-2025**
Permittee: **Blue Racer Midstream, LLC**
Facility Name: **Natrium Extraction and Fractionation Processing Plant (NEFPP) and Natrium Power Plant (NPP)**
Permittee Mailing Address: **14786 Energy Road, Proctor, WV 26055**

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45CSR30 - Requirements for Operating Permits. The permittee identified at the above-referenced facility is authorized to operate the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Facility Location:	Proctor, Marshall County, West Virginia
Facility Mailing Address:	14786 Energy Road, Proctor, WV 26055
Telephone Number:	(304) 455-4220
Type of Business Entity:	LLC
Facility Description:	Natural Gas Extraction/Fractionation Facility
SIC Codes:	Primary: 1321; Secondary: 4911
UTM Coordinates:	512.1 km Easting • 4,400.8 km Northing • Zone 17

Permit Writer: Sarah Barron

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§ 22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §22-5-14.

Issuance of this Title V Operating Permit does not supersede or invalidate any existing permits under 45CSR13, 14 or 19, although all applicable requirements from such permits governing the facility's operation and compliance have been incorporated into the Title V Operating Permit.

Table of Contents

1.0. Emission Units and Active R13, R14, and R19 Permits 3

2.0. General Conditions 9

3.0. Facility-Wide Requirements and Permit Shield 17

Source-specific Requirements

4.0. Hot Oil Heaters 26

5.0. Cryogenic HMO/Stabilizer Heaters 35

6.0. Regeneration Gas Heaters 40

7.0. Fire Pumps 42

8.0. Glycol Dehydration Units 48

9.0. 40 CFR 60, Subparts Kb and Kc Storage Tanks 51

10.0. Flare 65

11.0. Ethane Amine Units 71

12.0. Other Storage Tanks and Liquids Loading/Unloading 73

13.0. Pigging Operations 75

14.0. 40 CFR 60, Subparts OOOO, OOOOa, and OOOOb Requirements 78

15.0. NPP: Turbines and Duct Burners 135

16.0. NPP: Fuel Gas Heaters 156

17.0. NPP: Emergency Generator and Emergency Fire Pump Engine 158

18.0. NPP: Storage Tanks 166

19.0. NPP: Component Leaks 167

1.0 Emission Units and Active R13, R14, and R19 Permits

1.1. Emission Units

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Heaters					
S001	P001	Hot Oil Heater	2014	216.7 MMBtu/hr	None
S012	P012	Regeneration Gas Heater	2013	9.7 MMBtu/hr	None
S013	P013	Cryogenic Hot Medium Oil (HMO) Heater	2013	26.3 MMBtu/hr	None
S016	P016	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S017	P017	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S018	P018	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S019	P019	Hot Oil Heater	2014	61.58 MMBtu/hr	None
S024	P024	Regeneration Gas Heater	2018	9.7 MMBtu/hr	None
S026	P026	Cryogenic HMO Heater	2018	26.3 MMBtu/hr	None
S036	P036	Regeneration Gas Heater	2019	9.7 MMBtu/hr	None
S037	P037	Cryogenic HMO Heater	2019	26.3 MMBtu/hr	None
S040	P040	Regeneration Gas Heater	Not Yet Constructed	19.28 MMBtu/hr	None
S041	P041	Cryogenic HMO Heater	Not Yet Constructed	54.67 MMBtu/hr	None
S044	P044	Regeneration Gas Heater	Not Yet Constructed	9.7 MMBtu/hr	None
S045	P045	Cryogenic HMO Heater	Not Yet Constructed	26.3 MMBtu/hr	None
S048	P048	Regeneration Gas Heater	Not Yet Constructed	9.7 MMBtu/hr	None
S049	P049	Cryogenic HMO Heater	Not Yet Constructed	26.3 MMBtu/hr	None
S052	P052	Hot Oil Heater	Not Yet Constructed	61.58 MMBtu/hr	None
S053	P053	Hot Oil Heater	Not Yet Constructed	61.58 MMBtu/hr	None
S056	P056	Stabilizer Heater	Not Yet Constructed	10.09 MMBtu/hr	None

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Glycol Dehydration Units					
S006	P001[1]	Glycol Dehydration System Glycol Dehydration Flash Tank	2011	460 mmscf/day	C001[1]
Storage Tanks[2]					
TK-802	P001	Natural Gasoline Storage Tank	2011	714,000 gal	VRU and Natural Gas Blanket[3]
TK-2802	P001	Natural Gasoline Storage Tank	2014	1,260,000 gal	VRU and Natural Gas Blanket[3]
TK-3802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	714,000 gal	VRU and Natural Gas Blanket[3]
TK-4802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	1,260,000 gal	VRU and Natural Gas Blanket[3]
TK-5802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	714,000 gal	VRU and Natural Gas Blanket[3]
TK-6802	P001	Natural Gasoline Storage Tank	Not Yet Constructed	1,260,000 gal	VRU and Natural Gas Blanket[3]
TK-7802	TK-7802	Refrigerated Propane Storage Tank	Not Yet Constructed	4,200,000 gal	VRU
US-800	Flare[4]	Spherical NGL Storage Tank	2011	2,142,000 gal	Pressure Tank
US-801	Flare[4]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank
US-804	Flare[4]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank
US-805	Flare[4]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank
US-2800	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	2,142,000 gal	Pressure Tank
US-2801	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	865,200 gal	Pressure Tank

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
US-2804	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	865,200 gal	Pressure Tank
US-2805	Flare[4]	Spherical NGL Storage Tank	Not Yet Constructed	865,200 gal	Pressure Tank
N/A	N/A	Four (4) Pressurized NGL Bullet Tanks (V-1905, V-1915, V-1925, V-1935)	2014	90,000 gal (each)	Pressure Tank
N/A	N/A	Four (4) Pressurized NGL Bullet Tanks (V-2905, V-2915, V-2925, V-2935)	Not Yet Constructed	90,000 gal (each)	Pressure Tank
TK-906	TK-906	Slop Tank	2011	21,000 gal	None
TK-2906	TK-2906	Slop Tank	Not Yet Constructed	21,000 gal	None
TK-907	TK-907	Produced Water Tank	2012	63,000 gal	None
TK-2907	TK-2907	Produced Water Tank	Not Yet Constructed	63,000 gal	None
Other Emission Units					
S011	P005	Ethane Amine Regenerator	2012	129 mmscf/day	None
S054	P054	Ethane Amine Regenerator	Not Yet Constructed	129 mmscf/day	VRU
S008	P008	Product Loading (Truck, Rail, Propane Barge)	2011	3,600 gpm (truck) 4,000 gpm (rail) 4,000 gpm (barge)	VRU
S015	S015	Slop Water Truck Loading	2011	150 gpm	None
S033	P033	Natural Gasoline Loading (Barge)	2017	4,000 gpm	None
S055	P055	Pressurized NGL/Condensate Unloading	2012	3,600 gpm	None
L-1	L-1	Gasoline Dispenser Loading	2017	20 gal/hr	None
S002	P002	Caterpillar Model C18 Fire Pump #1 Diesel (Manufactured 2011)	2012	700 HP	None
S003	P003	Caterpillar Model C18 Fire Pump #2 Diesel (Manufactured 2011)	2012	700 HP	None
S058	P058	Diesel-Fired Fire Pump Engines/Generators[6]	2020	3,000 HP (total)	None
S035	P035	Pigging Operations	2017	N/A	VRU/ None[5]

Natrium Extraction and Fractionation Processing Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device
Fugitive Emissions Sources					
FUG AREA 1	N/A	Fugitive Area 1	2011	N/A	None
FUG AREA 2	N/A	Fugitive Area 2	2011	N/A	None
FUG AREA 3	N/A	Fugitive Area 3	2018	N/A	None
FUG AREA 4	N/A	Fugitive Area 4	2019	N/A	None
FUG AREA 5	N/A	Fugitive Area 5	Not Yet Constructed	N/A	None
FUG AREA 6	N/A	Fugitive Area 6	Not Yet Constructed	N/A	None
FUG AREA 7	N/A	Fugitive Area 7	Not Yet Constructed	N/A	None
S010	N/A	Unpaved Roads	2011	N/A	None
Control Devices					
S004A	P004A	Callidus CAL-MP Staged, Multi-Point Ground Flare System (C004A)	2015	19,800,000 scf/hr	N/A
S034	P034	Propane Pig Trap Flare (C034)	2017	72,000 scf/hr	N/A

Control Device ID	Emission Unit	Pollutant	Control Device	Control Efficiency
C004A	Maintenance, Blowdowns, Pressure Relief Valves	VOCs	Flare (S004A)	98.0 %
		Total HAPs		98.0 %
C034	Pigging Flare (S034)	VOCs	Pigging Flare (S034)	98.0%

(1) Still vent and flash tank vapors from S006 will be routed to the Hot Oil Heater (S001: C001) and used as fuel.

(2) Other storage tanks that are not listed here (see Table N-3 in permit application R13-2896F) but meet the *de minimis* requirements under 45CSR13 (*Storage vessels having less than 10,567 gallons capacity containing petroleum or organic liquids with a vapor pressure of 1.5 psia or less at storage temperature, provided that the emissions from all such organic liquid storage tanks, in the aggregate, are less than 2 tons per year for hazardous air pollutants or VOCs*) are authorized at the facility.

(3) Tank uses a natural gas blanket to prevent emissions of natural gasoline. Working/breathing losses of natural gas blanket are collected by a VRU and sent to Hot Oil Heater (S001) as a supplemental fuel.

(4) This tank shall be pressurized in excess of 204.9 kPa (which exempts the tank from applicability to 40 CFR 60, Subpart Kb) and normally has no emissions. In the case of emergency, emissions from the tank can be flared in C004A.

(5) The pigging vapors from the three truck side 30" Inlet receivers are captured by the VRU and routed back to the process.

(6) Under R13-2896I, the construction of one or more diesel-fired fire pump engines with a maximum total rating of 3,000 HP was permitted as emission unit S058. As of the writing of this operating permit, two 800-HP fire pump engines have been installed at the facility under the emission unit ID S058.

Note: Other storage tanks and pressure vessels not listed within the Title V Equipment Table are authorized at this facility according to insignificant activities listed under the Title V General Form Section 24, Item 19.

Natrium Power Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device[1]
Combustion Turbines[2]					
Scenario A					
TB1A	TB1AE	GE LM6000PG SPRINT Combustion Turbine #1	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC1, SCR1
TB2A	TB2AE	GE LM6000PG SPRINT Combustion Turbine #2	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC2, SCR2
TB3A	TB3AE	GE LM6000PG SPRINT Combustion Turbine #3	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC3, SCR3
TB4A	TB4AE	GE LM6000PG SPRINT Combustion Turbine #4	Not Yet Constructed	55.275 MW 482.6 MMBtu/hr	OC4, SCR4
Scenario B					
TB1B	TB1BE	Siemens SGT-800 Combustion Turbine #1	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC1, SCR1
TB2B	TB2BE	Siemens SGT-800 Combustion Turbine #2	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC2, SCR2
TB3B	TB3BE	Siemens SGT-800 Combustion Turbine #3	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC3, SCR3
TB4B	TB4BE	Siemens SGT-800 Combustion Turbine #4	Not Yet Constructed	57.863 MW 496.2 MMBtu/hr	OC4, SCR4
Other Combustion Devices					
TB1A/B	TB1A/BE	Duct Burner #1	Not Yet Constructed	475.1 MMBtu/hr	OC1, SCR1
TB2A/B	TB2A/BE	Duct Burner #2	Not Yet Constructed	475.1 MMBtu/hr	OC2, SCR2
TB3A/B	TB3A/BE	Duct Burner #3	Not Yet Constructed	475.1 MMBtu/hr	OC3, SCR3
TB4A/B	TB4A/BE	Duct Burner #4	Not Yet Constructed	475.1 MMBtu/hr	OC4, SCR4
FH1	FH1E	Fuel Gas Heater #1	Not Yet Constructed	9.9 MMBtu/hr	None
FH2	FH2E	Fuel Gas Heater #2	Not Yet Constructed	9.9 MMBtu/hr	None
EG1	EG1E	Emergency Generator	Not Yet Constructed	1,676 HP	None

Natrium Power Plant

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device[1]
FP1	FP1E	Emergency Fire Pump Engine	Not Yet Constructed	700 HP	None
Storage Tanks					
OT1 to OT4	OT1E to OT4E	Lubricating Oil Tank #1-4[3]	Not Yet Constructed	5,000 gal	None
OT5 to OT8	OT5E to OT8E	Waste Oil Tank #1-4[3]	Not Yet Constructed	250 gal	None
AT1	AT1E	Ammonia/Urea Storage Tank[4]	Not Yet Constructed	60,000 gal	None
WS1 to WS4	WS1E to WS4E	Washout Sumps #1-4[3]	Not Yet Constructed	250 gal	None
GT1 to GT4	GT1E to GT4E	Glycol Tanks #1-4[3]	Not Yet Constructed	1,000 gal	None
FT1	FT1E	Generator Fuel Tank[3]	Not Yet Constructed	25 gal	None
FT2	FT2E	Fire Pump Engine Fuel Tank[3]	Not Yet Constructed	25 gal	None
Fugitive Emission Sources					
EL1	N/A	Equipment Leaks	Not Yet Constructed	N/A	N/A

(1) OC = Oxidation Catalyst; SCR = Selective Catalytic Reduction

(2) BRM has permitted two (2) distinct and independent operational scenarios involving different sets of four (4) Combustion Turbines (CTs). Only one scenario will be permitted for the site. No more than four CTs (of the same set) will be permitted to be operated at the site.

(3) Pursuant to 45CSR13, Table 45-13B, defined as a *de minimis* source but included here for completeness.

(4) Ammonia/Urea are not regulated pollutants but the storage tank is included here for completeness.

1.2. Active R13, R14, and R19 Permits

The underlying authority for any conditions from R13, R14, and/or R19 permits contained in this operating permit is cited using the original permit number (e.g. R13-1234). The current applicable version of such permit(s) is listed below.

Permit Number	Date of Issuance
R13-2896K	August 17, 2023
R13-3493	December 15, 2020

2.0 General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45CSR§30-2.39.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.1.4. Unless otherwise specified in a permit condition or underlying rule or regulation, all references to a "rolling yearly total" shall mean the sum of the monthly data, values or parameters being measured, monitored, or recorded, at any given time for the previous twelve (12) consecutive calendar months.

2.2. Acronyms

CAAA	Clean Air Act Amendments	**NSPS**	New Source Performance Standards
CBI	Confidential Business Information	**PM**	Particulate Matter
CEM	Continuous Emission Monitor	**PM_{10}**	Particulate Matter less than 10μm in diameter
CES	Certified Emission Statement	**pph**	Pounds per Hour
C.F.R. *or* CFR	Code of Federal Regulations	**ppm**	Parts per Million
CO	Carbon Monoxide	**PSD**	Prevention of Significant Deterioration
C.S.R. *or* CSR	Codes of State Rules	**psi**	Pounds per Square Inch
DAQ	Division of Air Quality	**SIC**	Standard Industrial Classification
DEP	Department of Environmental Protection	**SIP**	State Implementation Plan
FOIA	Freedom of Information Act	**SO_2**	Sulfur Dioxide
HAP	Hazardous Air Pollutant	**TAP**	Toxic Air Pollutant
HON	Hazardous Organic NESHAP	**TPY**	Tons per Year
HP	Horsepower	**TRS**	Total Reduced Sulfur
lbs/hr *or* lb/hr	Pounds per Hour	**TSP**	Total Suspended Particulate
LDAR	Leak Detection and Repair	**USEPA**	United States Environmental Protection Agency
m	Thousand	**UTM**	Universal Transverse Mercator
MACT	Maximum Achievable Control Technology	**VEE**	Visual Emissions Evaluation
mm	Million	**VOC**	Volatile Organic Compounds
mmBtu/hr	Million British Thermal Units per Hour		
$mmft^3$/hr *or* mmcf/hr	Million Cubic Feet Burned per Hour		
NA *or* N/A	Not Applicable		
NAAQS	National Ambient Air Quality Standards		
NESHAPS	National Emissions Standards for Hazardous Air Pollutants		
NO_x	Nitrogen Oxides		

2.3. Permit Expiration and Renewal

2.3.1. Permit duration. This permit is issued for a fixed term of five (5) years and shall expire on the date specified on the cover of this permit, except as provided in 45CSR§30-6.3.b. and 45CSR§30-6.3.c.
[45CSR§30-5.1.b.]

2.3.2. A permit renewal application is timely if it is submitted at least six (6) months prior to the date of permit expiration.
[45CSR§30-4.1.a.3.]

2.3.3. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with 45CSR§30-6.2. and 45CSR§30-4.1.a.3.
[45CSR§30-6.3.b.]

2.3.4. If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.
[45CSR§30-6.3.c.]

2.4. Permit Actions

2.4.1. This permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
[45CSR§30-5.1.f.3.]

2.5. Reopening for Cause

2.5.1. This permit shall be reopened and revised under any of the following circumstances:

a. Additional applicable requirements under the Clean Air Act or the Secretary's legislative rules become applicable to a major source with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 45CSR§§30-6.6.a.1.A. or B.

b. Additional requirements (including excess emissions requirements) become applicable to an affected source under Title IV of the Clean Air Act (Acid Deposition Control) or other legislative rules of the Secretary. Upon approval by U.S. EPA, excess emissions offset plans shall be incorporated into the permit.

c. The Secretary or U.S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

d. The Secretary or U.S. EPA determines that the permit must be revised or revoked and reissued to assure compliance with the applicable requirements.

[45CSR§30-6.6.a.]

2.6. Administrative Permit Amendments

2.6.1. The permittee may request an administrative permit amendment as defined in and according to the procedures specified in 45CSR§30-6.4.
[45CSR§30-6.4.]

2.7. Minor Permit Modifications

2.7.1. The permittee may request a minor permit modification as defined in and according to the procedures specified in 45CSR§30-6.5.a.
[45CSR§30-6.5.a.]

2.8. Significant Permit Modification

2.8.1. The permittee may request a significant permit modification, in accordance with 45CSR§30-6.5.b., for permit modifications that do not qualify for minor permit modifications or as administrative amendments.
[45CSR§30-6.5.b.]

2.9. Emissions Trading

2.9.1. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit and that are in accordance with all applicable requirements.
[45CSR§30-5.1.h.]

2.10. Off-Permit Changes

2.10.1. Except as provided below, a facility may make any change in its operations or emissions that is not addressed nor prohibited in its permit and which is not considered to be construction nor modification under any rule promulgated by the Secretary without obtaining an amendment or modification of its permit. Such changes shall be subject to the following requirements and restrictions:

a. The change must meet all applicable requirements and may not violate any existing permit term or condition.

b. The permittee must provide a written notice of the change to the Secretary and to U.S. EPA within two (2) business days following the date of the change. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the permit shield.

d. The permittee shall keep records describing all changes made at the source that result in emissions of regulated air pollutants, but not otherwise regulated under the permit, and the emissions resulting from those changes.

e. No permittee may make any change subject to any requirement under Title IV of the Clean Air Act (Acid Deposition Control) pursuant to the provisions of 45CSR§30-5.9.

f. No permittee may make any changes which would require preconstruction review under any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) pursuant to the provisions of 45CSR§30-5.9.

[45CSR§30-5.9.]

2.11. Operational Flexibility

2.11.1. The permittee may make changes within the facility as provided by § 502(b)(10) of the Clean Air Act. Such operational flexibility shall be provided in the permit in conformance with the permit application and applicable requirements. No such changes shall be a modification under any rule or any provision of Title I of the Clean Air Act (including 45CSR14 and 45CSR19) promulgated by the Secretary in accordance with Title I of the Clean Air Act and the change shall not result in a level of emissions exceeding the emissions allowable under the permit.
[45CSR§30-5.8]

2.11.2. Before making a change under 45CSR§30-5.8., the permittee shall provide advance written notice to the Secretary and to U.S. EPA, describing the change to be made, the date on which the change will occur, any changes in emissions, and any permit terms and conditions that are affected. The permittee shall thereafter maintain a copy of the notice with the permit, and the Secretary shall place a copy with the permit in the public file. The written notice shall be provided to the Secretary and U.S. EPA at least seven (7) days prior to the date that the change is to be made, except that this period may be shortened or eliminated as necessary for a change that must be implemented more quickly to address unanticipated conditions posing a significant health, safety, or environmental hazard. If less than seven (7) days notice is provided because of a need to respond more quickly to such unanticipated conditions, the permittee shall provide notice to the Secretary and U.S. EPA as soon as possible after learning of the need to make the change.
[45CSR§30-5.8.a.]

2.11.3. The permit shield shall not apply to changes made under 45CSR§30-5.8., except those provided for in 45CSR§30-5.8.d. However, the protection of the permit shield will continue to apply to operations and emissions that are not affected by the change, provided that the permittee complies with the terms and conditions of the permit applicable to such operations and emissions. The permit shield may be reinstated for emissions and operations affected by the change:

a. If subsequent changes cause the facility's operations and emissions to revert to those authorized in the permit and the permittee resumes compliance with the terms and conditions of the permit, or

b. If the permittee obtains final approval of a significant modification to the permit to incorporate the change in the permit.

[45CSR§30-5.8.c.]

2.11.4. "Section 502(b)(10) changes" are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.
[45CSR§30-2.40]

2.12. Reasonably Anticipated Operating Scenarios

2.12.1. The following are terms and conditions for reasonably anticipated operating scenarios identified in this permit.

a. Contemporaneously with making a change from one operating scenario to another, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating and to document the change in reports submitted pursuant to the terms of this permit and 45CSR30.

b. The permit shield shall extend to all terms and conditions under each such operating scenario; and

c. The terms and conditions of each such alternative scenario shall meet all applicable requirements and the requirements of 45CSR30.

[45CSR§30-5.1.i.]

2.13. Duty to Comply

2.13.1. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.
[45CSR§30-5.1.f.1.]

2.14. Inspection and Entry

2.14.1. The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

[45CSR§30-5.3.b.]

2.15. Schedule of Compliance

2.15.1. For sources subject to a compliance schedule, certified progress reports shall be submitted consistent with the applicable schedule of compliance set forth in this permit and 45CSR§30-4.3.h., but at least every six (6) months, and no greater than once a month, and shall include the following:

a. Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones or compliance were achieved; and

b. An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measure adopted.

[45CSR§30-5.3.d.]

2.16. Need to Halt or Reduce Activity not a Defense

2.16.1. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.
[45CSR§30-5.1.f.2.]

2.17. Reserved

2.18. Federally-Enforceable Requirements

2.18.1. All terms and conditions in this permit, including any provisions designed to limit a source's potential to emit and excepting those provisions that are specifically designated in the permit as "State-enforceable only", are enforceable by the Secretary, USEPA, and citizens under the Clean Air Act.
[45CSR§30-5.2.a.]

2.18.2. Those provisions specifically designated in the permit as “State-enforceable only” shall become “Federally-enforceable” requirements upon SIP approval by the USEPA.

2.19. Duty to Provide Information

2.19.1. The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records required to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.
[45CSR§30-5.1.f.5.]

2.20. Duty to Supplement and Correct Information

2.20.1. Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.
[45CSR§30-4.2.]

2.21. Permit Shield

2.21.1. Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance provided that such applicable requirements are included and are specifically identified in this permit or the Secretary has determined that other requirements specifically identified are not applicable to the source and this permit includes such a determination or a concise summary thereof.
[45CSR§30-5.6.a.]

2.21.2. Nothing in this permit shall alter or affect the following:

a. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance; or

b. The applicable requirements of the Code of West Virginia and Title IV of the Clean Air Act (Acid Deposition Control), consistent with § 408 (a) of the Clean Air Act.

c. The authority of the Administrator of U.S. EPA to require information under § 114 of the Clean Air Act or to issue emergency orders under § 303 of the Clean Air Act.

[45CSR§30-5.6.c.]

2.22. Credible Evidence

2.22.1. Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defenses otherwise available to the permittee including but not limited to any challenge to the credible evidence rule in the context of any future proceeding.
[45CSR§30-5.3.e.3.B.]

2.23. Severability

2.23.1. The provisions of this permit are severable. If any provision of this permit, or the application of any provision of this permit to any circumstance is held invalid by a court of competent jurisdiction, the remaining permit terms and conditions or their application to other circumstances shall remain in full force and effect.
[45CSR§30-5.1.e.]

2.24. Property Rights

2.24.1. This permit does not convey any property rights of any sort or any exclusive privilege.
[45CSR§30-5.1.f.4]

2.25. Acid Deposition Control

2.25.1. Emissions shall not exceed any allowances that the source lawfully holds under Title IV of the Clean Air Act (Acid Deposition Control) or rules of the Secretary promulgated thereunder.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid deposition control program, provided that such increases do not require a permit revision under any other applicable requirement.

b. No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

c. Any such allowance shall be accounted for according to the procedures established in rules promulgated under Title IV of the Clean Air Act.

[45CSR§30-5.1.d.]

2.25.2. Where applicable requirements of the Clean Air Act are more stringent than any applicable requirement of regulations promulgated under Title IV of the Clean Air Act (Acid Deposition Control), both provisions shall be incorporated into the permit and shall be enforceable by the Secretary and U. S. EPA.
[45CSR§30-5.1.a.2.]

3.0 Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person is prohibited except as noted in 45CSR§6-3.1. **[45CSR§6-3.1.]**

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause or allow any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40 C.F.R. §61.145(b) and 45CSR34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1 State-Enforceable only.]

3.1.5. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45CSR11.
[45CSR§11-5.2]

3.1.6. **Emission inventory.** The permittee is responsible for submitting, on an annual basis, an emission inventory in accordance with the submittal requirements of the Division of Air Quality.
[W.Va. Code § 22-5-4(a)(15)]

3.1.7. **Ozone-depleting substances.** For those facilities performing maintenance, service, repair or disposal of appliances, the permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 C.F.R. Part 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the prohibitions and required practices pursuant to 40 C.F.R. §§ 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 C.F.R. § 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 C.F.R. § 82.161.

[40 C.F.R. 82, Subpart F]

3.1.8. **Risk Management Plan.** Should this stationary source, as defined in 40 C.F.R. § 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in 40 C.F.R. § 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 C.F.R. Part 70 or 71.
[40 C.F.R. 68]

3.1.9. **Minor Source of Hazardous Air Pollutants (HAP).** HAP emissions from the facility shall be less than 10 tons/year of any single HAP and 25 tons/year of any combination of HAPs. Compliance with this Section shall ensure that the facility is a minor HAP source.
[45CSR13, R13-2896, Condition 4.1.2.]

3.1.10. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.10.; 45CSR13, R13-2896, Condition 4.1.3.; 45CSR13, R13-3493, Condition 4.1.7.d.]

3.1.11. **Maximum Throughput Limitation.** The total maximum combined wet natural gas throughput of the gas processing plant, as processed in a maximum of seven (7) Cryogenic Plants, shall not exceed 1,945 mmscf/day. To demonstrate compliance, the permittee shall maintain records of the amount of natural gas processed in the gas processing plant.
[45CSR§13-5.10.; 45CSR13, R13-2896, Condition 4.1.5.]

3.1.12. No person shall cause, suffer, allow or permit fugitive particulate matter to be discharged beyond the boundary lines of the property on which the discharge originates or at any public or residential location, which causes or contributes to statutory air pollution.
[45CSR§17-3.1.]

3.1.13. When a person is found in violation of 45CSR17, the Director may require the person to utilize a system to minimize fugitive particulate matter. This system to minimize fugitive particulate matter may include, but is not limited to, the following:

a. Use, where practicable, of water or chemicals for control of particulate matter in demolition of existing buildings or structures, construction operations, grading of roads or the clearing of land;

b. Application of asphalt, water or suitable chemicals on unpaved roads, material stockpiles and other surfaces which can create airborne particulate matter;

c. Covering of material transport vehicles, or treatment of cargo, to prevent contents from dripping, sifting, leaking or otherwise escaping and becoming airborne, and prompt removal of tracked material from roads or streets; or

d. Installation and use of hoods, fans and fabric filters to enclose and vent the handling of materials including adequate containment methods during sandblasting, abrasive cleaning or other similar operations.

[45CSR§17-3.2.]

3.1.14. Only the emission unit/source identified in the table titled "Natrium Power Plant" in Section 1.1., with the exception of any *de minimis* sources as identified under Table 45-13B of 45CSR13, is authorized at the permitted Natrium Power Plant by R13-3493. In accordance with the information filed in Permit Application R13-3493, the emission unit/source identified under the table shall not exceed the listed maximum design capacity and comply with any other information provided under the table.
[45CSR13, R13-3493, 4.1.1.]

3.1.15. Upon construction of the equipment in the Emission Units Table specified as "Not Yet Constructed", the permittee shall meet all applicable requirements for the emission units. The permittee shall notify the Secretary, in writing or electronically, of the actual date of the initial startup of these emission units no later than thirty calendar days after such date. Within 180 days of equipment startup, the permittee shall submit, as necessary, a complete application for a significant Title V permit modification pursuant to 45CSR30 to incorporate any amendments or revisions of the applicable requirements.
[45CSR13, R13-2896, Section 2.18.; 45CSR13, R13-3493, Section 2.18.; 45CSR§30-6.5.b.]

3.2. Monitoring Requirements

3.2.1. **Emission Limit Averaging Time.** Unless otherwise specified, compliance with all annual limits shall be based on a rolling twelve-month total. A rolling twelve-month total shall be the sum of the measured parameter of the previous twelve calendar months. Compliance with all hourly emission limits shall be based on the applicable NAAQS averaging times or, where applicable, as given in any approved performance test method.
[45CSR13, R13-2896, Condition 3.2.1.; 45CSR13, R13-3493, Condition 3.2.1.]

3.2.2. **Maximum Design Capacity Compliance.** Compliance with the maximum design capacity limitations as given under Sections 15.1. to 19.1. of this operating permit (Section 4.1. of R13-3493) shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a throughput or production rate that does not exceed the specified value under Section 15.1. to 19.1.
[45CSR13, R13-3493, Condition 4.2.1.]

3.2.3. **Maximum Design Heat Input Compliance.** Compliance with the various combustion unit MDHI limitations as given under Sections 15.1. to 19.1. of this operating permit (Section 4.1. of R13-3493) shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) in question is limited by design to an MDHI that does not exceed the specified value under Sections 15.1. to 19.1.
[45CSR13, R13-3493, Condition 4.2.2.]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or

established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63, if applicable, in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit shall be revised iin accordance with 45CSR§30-6.4. or 45CSR§30-6.5., as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within 60 days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

    1. The permit or rule evaluated, with the citation number and language.

    2. The result of the test for each permit or rule condition.

    3. A statement of compliance or non-compliance with each permit or rule condition.

[WV Code §§ 22-5-4(a)(15-16) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Monitoring information.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

[45CSR§30-5.1.c.2.A.; 45CSR13, R13-2896, Condition 4.1.1.; 45CSR13, R13-3493, Condition 4.4.1.]

3.4.2. **Retention of records.** The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of monitoring sample, measurement, report, application, or record creation date. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Where appropriate, records may be maintained in computerized form in lieu of the above records.
[45CSR§30-5.1.c.2.B.; 45CSR13, R13-2896, Condition 3.4.1.; 45CSR13, R13-3493, Condition 3.4.1.]

3.4.3. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§30-5.1.c. State-Enforceable only.]

3.4.4. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

[45CSR13, R13-2896, Condition 4.1.4.]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.
[45CSR§§30-4.4. *and* 5.1.c.3.D.]

3.5.2. A permittee may request confidential treatment for the submission of reporting required under 45CSR§30-5.1.c.3. pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.
[45CSR§30-5.1.c.3.E.]

3.5.3. Except for the electronic submittal of the annual compliance certification and semi-annual monitoring reports to the DAQ and USEPA as required in 3.5.5 and 3.5.6 below, all notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class or by private carrier with postage prepaid to the address(es), or submitted in electronic format by e-mail as set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

DAQ:

Director
WVDEP
Division of Air Quality
601 57th Street SE
Charleston, WV 25304

US EPA:

Section Chief
U. S. Environmental Protection Agency, Region III
Enforcement and Compliance Assurance Division
Air, RCRA, and Toxics Branch (3ED21)
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2852

DAQ Compliance and Enforcement[1]:
DEPAirQualityReports@wv.gov

[1]For all self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status reports, Initial Notifications, etc.

3.5.4. **Fees.** The permittee shall pay fees on an annual basis in accordance with 45CSR§30-8.
[45CSR§30-8.]

3.5.5. **Compliance certification.** The permittee shall certify compliance with the conditions of this permit on the forms provided by the DAQ. In addition to the annual compliance certification, the permittee may be required to submit certifications more frequently under an applicable requirement of this permit. The annual certification shall be submitted to the DAQ and USEPA on or before March 15 of each year, and shall certify compliance for the period ending December 31. The permittee shall maintain a copy of the certification on site for five (5) years from submittal of the certification. The annual certification shall be submitted in electronic format by e-mail to the following addresses:

DAQ:	**US EPA:**
DEPAirQualityReports@wv.gov	R3_APD_Permits@epa.gov

[45CSR§30-5.3.e.]

3.5.6. **Semi-annual monitoring reports.** The permittee shall submit reports of any required monitoring on or before September 15 for the reporting period January 1 to June 30 and on or before March 15 for the reporting period July 1 to December 31. All instances of deviation from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with 45CSR§30-4.4. The semi-annual monitoring reports shall be submitted in electronic format by e-mail to the following address:

DAQ:
DEPAirQualityReports@wv.gov

[45CSR§30-5.1.c.3.A.]

3.5.7. **Reserved.**

3.5.8. **Deviations.**

a. In addition to monitoring reports required by this permit, the permittee shall promptly submit supplemental reports and notices in accordance with the following:

1. Reserved.

2. Any deviation that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to the Secretary immediately by telephone or email. A written report of such deviation, which shall include the probable cause of such deviation, and any corrective actions or preventative measures taken, shall be submitted by the responsible official within ten (10) days of the deviation.

3. Deviations for which more frequent reporting is required under this permit shall be reported on the more frequent basis.

4. All reports of deviations shall identify the probable cause of the deviation and any corrective actions or preventative measures taken.

[45CSR§30-5.1.c.3.C.]

b. The permittee shall, in the reporting of deviations from permit requirements, including those attributable to upset conditions as defined in this permit, report the probable cause of such deviations and any corrective actions or preventive measures taken in accordance with any rules of the Secretary. **[45CSR§30-5.1.c.3.B.]**

3.5.9. **New applicable requirements.** If any applicable requirement is promulgated during the term of this permit, the permittee will meet such requirements on a timely basis, or in accordance with a more detailed schedule if required by the applicable requirement. **[45CSR§30-4.3.h.1.B.]**

3.6. Compliance Plan

3.6.1. None

3.7. Permit Shield

3.7.1. The permittee is hereby granted a permit shield in accordance with 45CSR§30-5.6. The permit shield applies provided the permittee operates in accordance with the information contained within this permit.

3.7.2. The following requirements specifically identified are not applicable to the source based on the determinations set forth below. The permit shield shall apply to the following requirements provided the conditions of the determinations are met.

a. 45CSR19 – *Permits for Construction and Major Modification of Major Stationary Sources Which Cause or Contribute to Nonattainment Areas*: This rule establishes a preconstruction permit program for any area designated nonattainment for any national ambient air quality standard (NAAQS) and applies to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment. Marshall County is currently designated as in attainment for the NAAQS. Therefore, 45CSR19 is inapplicable.

b. 45CSR27 – *To Prevent and Control the Emissions of Toxic Air Pollutants*: Natural gas is included as a petroleum product and contains less than 5% benzene by weight. 45CSR§27-2.4. exempts equipment "used in the production and distribution of petroleum products providing that such equipment does not produce or contact materials containing more than 5% benzene by weight."

c. 40 CFR 60, Subparts TTTT and TTTTa – *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*: Per §60.5509(b)(3) and §60.5509a(b)(3), an electric generating unit is not subject to Subpart TTTT or TTTTa if the unit is a combined heat and power unit subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater. Under Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of this operating permit), the amount of power supplied by each turbine to the utility distribution systems is limited to 219,000 MWh per year. Therefore, per §60.5509(b)(3) and §60.5509a(b)(3), the turbines are not subject to Subparts TTTT and TTTTa.

d. 40 CFR 63, Subpart HH – *National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities*: The facility is not subject to the equipment leak standards under 40 CFR §63.769 because it is an area source of HAPs, which limits applicability under Subpart HH to only the (TEG) dehydration unit according to 40 CFR §63.760(b)(2).

e. 40 CFR 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*: In accordance with 40 CFR §63.7480, this subpart does not apply to the facility since it is not a major source of HAPs as defined in 40 CFR §63.7575.

f. 40 CFR 63, Subpart JJJJJJ – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources*: This subpart does not apply to the facility since the heaters are fueled by natural gas, and gas-fired boilers are exempt per 40 CFR §63.11195(e).

g. 40 CFR 97, Subpart AAAAA/CCCCC/GGGGG – *CSAPR NO_X Annual Trading Program/CSAPR SO_2 Group 1 Trading Program/CSAPR NO_X Ozone Season Group 3 Trading Program*: In accordance with §52.38(a)(2)(i) and §52.39(b), the provisions of 40 CFR 97, Subparts AAAAA and CCCCC are applicable to sources located in West Virginia with regard to emissions occurring in 2015 and each subsequent year; similarly, in accordance with §52.38(b)(2)(iii)(A), the provisions of 40 CFR 97, Subpart GGGGG are applicable to sources located in West Virginia with regard to emissions occurring in 2021 and each subsequent year. Per the applicability criteria of §97.404(a)(1), §97.604(a)(1), and §97.1004(a)(1), the sources considered to be subject to the CSAPR include any stationary, fossil fuel-fired boiler or stationary, fossil fuel-fired combustion turbine serving, at any time on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale. However, §97.404(b)(1)(i), §97.604(b)(1)(i), and §97.1004(b)(1)(i) exempt any unit that otherwise qualifies as a source subject to the CSAPR from Subparts AAAAA, CCCCC, and GGGGG, respectively, if the unit also qualifies as a cogeneration unit throughout the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year after such 12-month period and that does not supply in any calendar year more than one-third of its potential electrical output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. The turbines TB1A/B through TB4A/B are cogeneration units which produce heat and electricity for use at the facility and, under Condition 4.1.2.h. of R13-3493 (Condition 15.1.1.h. of this operating permit), are subject to a federally enforceable limit that restricts the maximum amount of power supplied by each turbine to the utility distribution system to less than 219,000 MWh per year. Therefore, the facility is not subject to the CSAPR NO_X Trading Program, the CSAPR SO_2 Group 1 Trading Program, nor the CSAPR NO_X Ozone Season Group 3 Trading Program, in accordance with §97.404(b)(1)(i), §97.604(b)(1)(i), and §97.1004(b)(1)(i), respectively.

4.0 Hot Oil Heaters [emission unit ID(s): S001, S016-S019, S052-S053]

4.1. Limitations and Standards

4.1.1. The MDHI of the Hot Oil Heater designated as S001 shall not exceed 216.7 MMBtu/hr and, for each Hot Oil Heater designated as S016-S019 and S052-S053, shall not exceed 61.58 MMBtu/hr. All Hot Oil Heaters (S001, S016-S019, S052-S053) shall be equipped with Low NO_X burners.
[45CSR13, R13-2896, Condition 5.1.1.]

4.1.2. Maximum emissions from the Hot Oil Heaters shall not exceed the following:

a. The maximum emissions from S001 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S001	Nitrogen Oxides	9.75	42.71
	Carbon Monoxide	3.25	14.24
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	1.61	7.07
	$SO_2^{(3)}$	0.15	0.67
	VOCs	0.37	1.61

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2. (condition 4.1.4.b)
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

b. The maximum emissions from each heater S016-S019 and S052-S053 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S016-S019, S052-S053	Nitrogen Oxides	1.48	6.47
	Carbon Monoxide	3.63	15.91
	$SO_2^{(3)}$	0.04	0.19
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.46	2.01
	VOCs	0.33	1.45

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2. (condition 4.1.4.b)
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13, R13-2896, Condition 5.1.2.]

4.1.3. The quantity of natural gas that shall be consumed in the 216.7 MMBtu/hr Hot Oil Heater (S001) shall not exceed 225,571 standard cubic feet per hour and 1,976 x 10^6 standard cubic feet per year. The quantity of

natural gas that shall be consumed in each 61.58 MMBtu/hr Hot Oil Heaters (S016-S019 and S052-S053) shall not exceed 64,101 standard cubic feet per hour and 562 x 10^6 standard cubic feet per year.
[45CSR13, R13-2896, Condition 5.1.3.]

4.1.4. **45CSR2**
Each Hot Oil Heater is subject to the applicable limitations and standards under 45CSR2, including the requirements as given below under a. through c.:

a. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

b. The permittee shall not cause, suffer, allow or permit the discharge of particulate matter into the open air from the fuel burning units, measured in terms of pounds per hour in excess of the amount determined as follows:

1. The product of 0.09 and the total design heat input for the fuel burning units in MMBtu/hr, provided however that no more than 600 lb/hr of particulate matter shall be discharged into the open air.

[45CSR§§2-4.1. and -4.1.2.]

[45CSR13, R13-2896, Condition 5.1.4.]

4.1.5. **40 CFR 60, Subpart Db**
Hot Oil heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db, including the requirements as given below under a. through c.:

a. Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in 40 CFR §60.42b(k)(1).
[45CSR16; 40 CFR §60.42b(k)(2)]

b. Except as provided under 40 CFR §§60.44b(k) and (l), on and after the date on which the initial performance test is completed or is required to be completed under 40 CFR §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of 40 CFR §60.44b and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

1. Low heat release rate: 0.10 lb/MMBtu

2. High heat release rate: 0.20 lb/MMBtu

[45CSR16; 40 CFR §§60.44b(a), (a)(1)(i), and (a)(1)(ii)]

c. Except as provided under 40 CFR §§60.48b(g), (h), and (i), the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs 40 CFR §60.48b(b)(1) or (b)(2).

1. Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system.

[45CSR16; 40 CFR §§60.48b(b) and (b)(1)]

d. Pursuant to 40 CFR §60.49b(r)(2)(iv), the WVDAQ approves quarterly fuel sampling for S001.

[45CSR13, R13-2896, Condition 5.1.5.]

4.1.6. **40 CFR 60, Subpart Dc**
Hot Oil Heaters S016-S019 and S052-S053 are subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated. Recordkeeping and reporting requirements shall be conducted in accordance with §60.48c. These reports shall be submitted in accordance with the timelines and in the order set forth in §60.48c and submitted to the addresses listed in Section 3.5.3.
[45CSR13, R13-2896, Condition 5.1.6.]

4.2. Monitoring Requirements

4.2.1. At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with section 4.1.4. of this permit. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.
[45CSR§2-3.2.; 45CSR13, R13-2896, Condition 5.2.1.]

4.2.2. **40 CFR 60, Subpart Db**
Hot Oil Heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db:

a. For purposes of 40 CFR §60.44b(i), the NO_X standards under 40 CFR §60.44b apply at all times including periods of startup, shutdown, or malfunction.
[45CSR16; 40 CFR §60.44b(h)]

b. Except as provided under 40 CFR §60.44b(j), compliance with the emission limits under 40 CFR §60.44b is determined on a 30-day rolling average basis.
[45CSR16; 40 CFR §60.44b(i)]

c. The CEMS required under 40 CFR §60.48b(b) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
[45CSR16; 40 CFR §60.48b(c)]

d. The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by condition 4.1.5. and required under 40 CFR §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under 40 CFR §60.44b. The 1-hour averages shall be calculated using the data points required under 40 CFR §60.13(h)(2).
[45CSR16; 40 CFR §60.48b(d)]

e. The procedures under 40 CFR §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

1. For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

   i. Except as provided under paragraph e.1.ii. of this condition, NO_X span values shall be determined as follows:

Fuel	Span Values for NO_X (ppm)
Natural Gas	500
Oil	500
Coal	1,000
Mixtures	500 (x + y) + 1,000z

   Where:
   x = Fraction of total heat input derived from natural gas;
   y = Fraction of total heat input derived from oil; and
   z = Fraction of total heat input derived from coal.

   ii. As an alternative to meeting the requirements of paragraph e.1.i. of this condition, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in Appendix A to 40 CFR 75.

2. All span values computed under paragraph e.1.i. of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph e.1.ii. of this section shall be rounded off according to section 2.1.2 in Appendix A to 40 CFR 75.

[45CSR16; 40 CFR §§60.48b(e), (e)(2), and (e)(3)]

f. When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of Appendix A of 40 CFR 60, Method 7A of Appendix A of 40 CFR 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.
[45CSR16; 40 CFR §60.48b(f)]

g. The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

   1. Comply with the provisions of 40 CFR §§60.48b(b), (c), (d), (e)(2), (e)(3), and (f).

   [45CSR16; 40 CFR §§60.48b(g) and (g)(1)]

4.3. Testing Requirements

4.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established under 4.1.2.a. and b.
[45CSR§§2-8.1.2. and -8.1.3.; 45CSR13, R13-2896, Condition 5.3.1.]

4.3.2. **40 CFR 60, Subpart Db**
Hot Oil Heater S001 is subject to the applicable compliance demonstration requirements of 40 CFR 60, Subpart Db:

To determine compliance with the emission limits for NO_X required under 40 CFR §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under 40 CFR §60.8 using the continuous system for monitoring NO_X under 40 CFR §60.48b(b).

a. Following the date on which the initial performance test is completed or required to be completed under 40 CFR §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in 40 CFR §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to 40 CFR §60.48b(g)(1) or (2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

[45CSR16; 40 CFR §§60.46b(c), 60.46b(e), and 60.46b(e)(4)]

4.4. Recordkeeping Requirements

4.4.1. **Records of Fuel Usage**

a. To demonstrate continuous compliance with sections 4.1.1. to 4.1.3., the permittee shall monitor and record the monthly and twelve (12) month rolling total of the amount of natural gas consumed in S001, S016 to S019, and S052 to S053.
[45CSR13, R13-2896, Condition 5.4.1.]

b. The owner or operator shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit in a manner to be established by the Secretary. Such records are to be maintained on-site and made available to the Secretary upon request.
[45CSR§2-8.3.3.]

c. The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified:

1. For fuel burning unit(s) which burn only pipeline quality natural gas, such records shall include, but not be limited to, the date and time of startup and shutdown, and the quantity of fuel consumed on a monthly basis.

[45CSR§§2A-7.1.a. and -7.1.a.1.]

4.4.2. **40 CFR 60, Subpart Db**

Hot Oil Heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db:

a. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.
[45CSR16; 40 CFR §60.49b(d)(1)]

b. The owner or operator of an affected facility subject to the NO_X standards under 40 CFR §60.44b shall maintain records of the following information for each steam generating unit operating day:

1. Calendar date;

2. The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

3. The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

4. Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

5. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

6. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

7. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

8. Identification of the times when the pollutant concentration exceeded full span of the CEMS;

9. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

10. Results of daily CEMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1 of 40 CFR 60.

[45CSR16; 40 CFR §60.49b(g)]

c. The owner or operator of an affected facility who elects to use the fuel-based compliance alternatives in 40 CFR §60.42b or §60.43b shall either:

1. The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in 40 CFR §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in 40 CFR §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

2. The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in 40 CFR §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date of the intended compliance demonstration. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

i. The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

ii. The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

iii. The ratio of different fuels in the mixture; and

iv. The owner or operator can petition the Administrator to approve monthly or quarterly (condition 4.1.5.d.) sampling in place of weekly sampling.

[45CSR16; 40 CFR §§60.45b(k), 60.47b(f), and 60.49b(r)]

d. All records required under 40 CFR §60.49b shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.
[45CSR16; 40 CFR §60.49b(o)]

4.4.3. **40 CFR 60, Subpart Dc**
Hot Oil Heaters S016-S019 and S052-S053 are subject to the following applicable provisions of 40 CFR 60, Subpart Dc:

a. Except as provided under paragraphs b. and c. of this condition, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.
[45CSR16; 40 CFR §60.48c(g)(1)]

b. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in 40 CFR §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(2)]

c. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to 40 CFR 60, Subpart Dc) at that property are natural gas, wood, distillate oil meeting the most current requirements in 40 CFR §60.42c to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(3)]

d. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
[45CSR16; 40 CFR §60.48c(i)]

4.5. Reporting Requirements

4.5.1. Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40 CFR 60, Appendix A, Method 9 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned.
[45CSR13, R13-2896, Condition 5.5.1.]

4.5.2. **40 CFR 60, Subpart Db**
Hot Oil Heater S001 is subject to the applicable limitations and standards under 40 CFR 60, Subpart Db:

a. The owner/operator is required to submit excess emission reports for any excess emissions that occurred during the reporting period.
[45CSR16; 40 CFR §§60.49b(h), (h)(2), and (h)(2)(i)]

b. For the purposes of 40 CFR §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under 40 CFR §60.46b(e), that exceeds the applicable emission limits in 40 CFR §60.44b.
[45CSR16; 40 CFR §60.49b(h)(4)]

c. The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under 40 CFR §60.48b(b) shall submit reports containing the information recorded under 40 CFR §60.49b(g).
[45CSR16; 40 CFR §60.49b(i)]

d. The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under 40 CFR §§60.49b(h), (i), (j), (k), or (l). The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of 40 CFR 60, Subpart Db was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.
[45CSR16; 40 CFR §60.49b(v)]

e. The reporting period for the reports required under 40 CFR 60, Subpart Db is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.
[45CSR16; 40 CFR §60.49b(w)]

4.6. Compliance Plan

4.6.1. None

5.0 Cryogenic HMO/Stabilizer Heaters [emission unit ID(s): S013, S026, S037, S041, S045, S049, S056]

5.1. Limitations and Standards

5.1.1. **Maximum Design Heat Input.** The maximum design heat input for the Cryogenic HMO Heaters shall not exceed 26.3 MMBtu/hr for units S013, S026, S037, S045, and S049 and 54.67 MMBtu/hr for unit S041. The maximum design heat input for the Stabilizer Heater (S056) shall not exceed 10.09 MMBtu/hr. **[45CSR13, R13-2896, Condition 6.1.1.]**

5.1.2. Maximum emissions from the Cryogenic HMO/Stabilizer Heaters shall not exceed the following:

a. The maximum emissions from Cryogenic HMO Heaters S013, S026, S037, S045, and S049 shall not exceed the following individual unit limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S013 S026 S037 S045 S049	Nitrogen Oxides	2.58	11.29
	Carbon Monoxide	2.17	9.49
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.20	0.86
	$SO_2^{(3)}$	0.02	0.08
	VOCs	0.14	0.62

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

b. The maximum emissions from Cryogenic HMO Heater S041 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S041	Nitrogen Oxides	5.36	23.48
	Carbon Monoxide	4.50	19.72
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.41	1.78
	$SO_2^{(3)}$	0.04	0.17
	VOCs	0.29	1.29

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

c. The maximum emissions from Stabilizer Heater S056 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S056	Nitrogen Oxides	0.99	4.33
	Carbon Monoxide	0.83	3.64
	$PM_{2.5}/PM_{10}/PM^{(1)(2)}$	0.08	0.33
	$SO_2^{(3)}$	0.01	0.03
	VOCs	0.05	0.24

(1) Includes Condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§2-4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§10-3.1.5.

[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13, R13-2896, Condition 6.1.2.]

5.1.3. To demonstrate compliance with Section 5.1.2., the quantity of natural gas that shall be consumed in each of the 26.3 MMBtu/hr Cryogenic HMO Heaters (S013, S026, S037, S045, S049) shall not exceed 27,377 standard cubic feet per hour and 240×10^6 standard cubic feet per year. The quantity of natural gas that shall be consumed in the 54.67 MMBtu/hr Cryogenic HMO Heater (S041) shall not exceed 56,908 standard cubic feet per hour and 499×10^6 standard cubic feet per year. The quantity of natural gas that shall be consumed in the 10.09 MMBtu/hr Stabilizer Heater (S056) shall not exceed 10,503 standard cubic feet per hour and 92×10^6 standard cubic feet per year.
[45CSR13, R13-2896, Condition 6.1.3.]

5.1.4. **45CSR2**
Each Cryogenic HMO and Stabilizer Heaters is subject to the applicable limitations and standards under 45CSR2, including the requirements as given below under a. amd b.:

a. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six-minute block average.
[45CSR§2-3.1.]

b. The permittee shall not cause, suffer, allow or permit the discharge of particulate matter into the open air from the fuel burning units, measured in terms of pounds per hour in excess of the amount determined as follows:

1. The product of 0.09 and the total design heat input for the fuel burning units in million British Thermal Units (B.T.U.'s) per hour, provided however that no more than six hundred (600) pounds per hour of particulate matter shall be discharged into the open air.

[45CSR§§2-4.1. and -4.1.2.]

[45CSR13, R13-2896, Condition 6.1.4.]

5.1.5. **40 CFR 60, Subpart Dc**

The Cryogenic HMO and Stabilizer Heaters are subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated. Recordkeeping and reporting requirements shall be conducted in accordance with 40 CFR §60.48c. These reports shall be submitted in accordance with the time lines and in the order set forth in 40 CFR §60.48c and submitted to the addresses listed in Section 3.5.3.

[45CSR13, R13-2896, Condition 6.1.5.]

5.2. Monitoring Requirements

5.2.1. At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with section 5.1.4. of this permit. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.

[45CSR13, R13-2896, Condition 6.2.1.]

5.3. Testing Requirements

5.3.1. Compliance with the visible emission requirements of section 5.1.4 shall be determined in accordance with 40 CFR 60, Appendix A, Method 9 or by using measurements from continuous opacity monitoring systems approved by the Secretary. The Secretary may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of section 5.1.4. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.

[45CSR§2-3.2.; 45CSR13, R13-2896, Condition 6.3.1.]

5.3.2. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3 of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established under 5.1.2.a., b., and c.

[45CSR§§2-8.1.2. and -8.1.3.]

5.4. Recordkeeping Requirements

5.4.1. **Records of Fuel Usage**

a. To demonstrate compliance with sections 5.1.1, 5.1.2, and 5.1.3, the permittee shall monitor and record the monthly and twelve-month rolling total of the amount of natural gas consumed in all heaters listed in this section.

[45CSR13, R13-2896, Condition 6.4.1.]

b. The owner or operator shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit in a manner to be established by the Director. Such records are to be maintained on-site and made available to the Director or his duly authorized representative upon request.

[45CSR§2-8.3.3.]

c. The owner or operator of a fuel burning unit(s) shall maintain records of the operating schedule, and the quality and quantity of fuel burned in each fuel burning unit as specified:

1. For fuel burning unit(s) which burn only pipeline quality natural gas, such records shall include, but not be limited to, the date and time of startup and shutdown, and the quantity of fuel consumed on a monthly basis.

[45CSR§§2A-7.1.a. and -7.1.a.1.]

5.4.2. The permittee shall maintain records of all monitoring data required by Section 5.2.1 documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s). Should a visible emission observation be required to be performed per the requirements specified in Method 9, the data records of each observation shall be maintained per the requirements of Method 9.
[45CSR13, R13-2896, Condition 6.4.2.]

5.4.3. **40 CFR 60, Subpart Dc**
The Cryogenic HMO and Stabilizer Heaters are subject to the following applicable provisions of 40 CFR 60, Subpart Dc:

a. Except as provided under paragraphs b. and c. of this condition, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.
[45CSR16; 40 CFR §60.48c(g)(1)]

b. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in 40 CFR §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(2)]

c. As an alternative to meeting the requirements of paragraph a. of this condition, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to 40 CFR 60, Subpart Dc) at that property are natural gas, wood, distillate oil meeting the most current requirements in 40 CFR §60.42c to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.
[45CSR16; 40 CFR §60.48c(g)(3)]

d. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
[45CSR16; 40 CFR §60.48c(i)]

5.5. Reporting Requirements

5.5.1. Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40 CFR 60, Appendix A, Method 9 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned. **[45CSR13, R13-2896, Condition 6.5.1.]**

5.6. Compliance Plan

5.6.1. None

6.0 Regeneration Gas Heaters [emission unit ID(s): S012, S024, S036, S040, S044, S048]

6.1. Limitations and Standards

6.1.1. **Maximum Design Heat Input.** The maximum design heat input of the Regeneration Gas Heaters shall not exceed 9.7 MMBtu/hr for units S012, S024, S036, S044, and S048 and 19.28 MMBtu/hr for unit S040. **[45CSR13, R13-2896, Condition 7.1.1.]**

6.1.2. Maximum emissions from the Regeneration Gas Heaters shall not exceed the following:

a. The maximum emissions from units S012, S024, S036, S044, and S048 shall not exceed the following individual unit limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S012 S024 S036 S044 S048	Nitrogen Oxides	0.95	4.17
	Carbon Monoxide	0.80	3.50
	$PM_{2.5}/PM_{10}/PM^{(1)}$	0.07	0.32
	VOCs	0.05	0.23

(1) Includes Condensables.

b. The maximum emissions from unit S040 shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S040	Nitrogen Oxides	1.89	8.28
	Carbon Monoxide	1.59	6.95
	$PM_{2.5}/PM_{10}/PM^{(1)}$	0.14	0.63
	VOCs	0.10	0.46

(1) Includes Condensables.

[45CSR13, R13-2896, Condition 7.1.2.]

6.1.3. To demonstrate compliance with Section 6.1.2., the quantity of natural gas that shall be consumed in each of the 9.7 MMBtu/hr Regeneration Gas Heaters (S012, S024, S036, S044, and S048) shall not exceed 10,097 standard cubic feet per hour and 88×10^6 standard cubic feet per year. The quantity of natural gas that shall be consumed in the 19.28 MMBtu/hr Regeneration Gas Heater (S040) shall not exceed 20,069 standard cubic feet per hour and 176×10^6 standard cubic feet per year.
[45CSR13, R13-2896, Condition 7.1.3.]

6.2. Monitoring Requirements

6.2.1. None

6.3. Testing Requirements

6.3.1. None

6.4. Recordkeeping Requirements

6.4.1. To demonstrate compliance with sections 6.1.1., 6.1.2., and 6.1.3., the permittee shall monitor and record the monthly and twelve month rolling total of the amount of natural gas consumed in all heaters listed in this section.
[45CSR13, R13-2896, Condition 7.4.1.]

6.5. Reporting Requirements

6.5.1. None

6.6. Compliance Plan

6.6.1. None

7.0 Fire Pumps [emission unit ID(s): S002, S003, S058]

7.1. Limitations and Standards

7.1.1. The quantity of diesel fuel that shall be consumed in each of the 700 HP diesel-fired fire pump engines, Caterpillar Model C18 (S002, S003) shall not exceed 35.9 gallons per hour and 3,590 gallons per rolling twelve (12) month period during non-emergency use.
[45CSR13, R13-2896, Condition 8.1.1.]

7.1.2. Maximum emissions from each of the 700 HP diesel-fired fire pumps, Caterpillar Model C18 (S002, S003) shall not exceed the following limits for the entire life of the engine:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S002 S003	NMHC + Nitrogen Oxides(1)	4.63	0.23
	Carbon Monoxide(1)	4.01	0.20
	$PM_{2.5}/PM_{10}/PM$(1)(2)	0.23	0.01
	Volatile Organic Compounds	4.63	0.23

(1) Calculated using emission limits in Table 4 of 40 CFR 60, Subpart IIII
(2) Includes Condensables
[45CSR16; 40 CFR §§60.4205(c) and 60.4206; Table 4 of 40 CFR 60, Subpart IIII; 45CSR13, R13-2896, Conditions 8.1.2. and 8.1.5.]

7.1.3. **Maximum Annual Operation Limitation.** The maximum yearly hours of operation for each of the 700 HP diesel-fired fire pump engine(s)/generator(s), Caterpillar Model C18 (S002, S003) and for each additional fire pump engine added as authorized under 7.1.8. shall not exceed an annual limit of 100 hours of non-emergency use as recorded with a non-resettable hour meter. Compliance with each Maximum Yearly Operation Limitation shall be determined using a twelve (12) month rolling total. A twelve (12) month rolling total shall mean the sum of the hours of operation at any given time during the previous twelve consecutive calendar months for each engine.
[45CSR13, R13-2896, Condition 8.1.4.]

7.1.4. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to 40 CFR 60, Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.
[45CSR16; 40 CFR §60.4207(b)]

7.1.5. **40 CFR 63, Subpart ZZZZ**
S002, S003, and S058 are each subject to all applicable regulations given under 40 CFR 63, Subpart ZZZZ including the following:

a. *Stationary RICE subject to Regulations under 40 CFR 60.* An affected source that meets any of the criteria in paragraphs 40 CFR §§63.6590(c)(1) through (7) must meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60,

Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under 40 CFR 63.

[45CSR34; 40 CFR §63.6590(c); 45CSR13, R13-2896, Condition 8.1.6.]

7.1.6. The permittee must satisfy the following compliance requirements:

a. If the permittee is an owner or operator and must comply with the emission standards specified in 40 CFR 60, Subpart IIII, the permittee must do all of the following, except as permitted under paragraph d. of this section:

1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

2. Change only those emission-related settings that are permitted by the manufacturer; and

3. Meet the requirements of 40 CFR 1068, as they apply to the permittee.

b. The permittee shall comply with the emission standards specified in 40 CFR §60.4205(c) by purchasing an engine certified to the emission standards. The unit must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph d. of this condition.

c. If the permittee owns or operates an emergency stationary ICE, the permittee must operate the emergency stationary ICE according to the requirements in paragraphs c.1. through 3. of this condition. In order for the engine to be considered an emergency stationary ICE, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs c.1. through 3. of this condition, is prohibited. If the permittee does not operate the engine according to the requirements in paragraphs c.1. through 3. of this condition, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.

1. There is no time limit on the use of emergency stationary ICE in emergency situations.

2. The permittee may operate the emergency stationary ICE for the purpose specified in paragraph c.2.i. of this condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph c.3. of this condition counts as part of the 100 hours per calendar year allowed by this paragraph c.2.

i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

3. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph c.2. of this section.

Except as provided in paragraph c.3.i. of this condition, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

i. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

a. The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

b. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

c. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

d. The power is provided only to the facility itself or to support the local transmission and distribution system.

e. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

d. If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as follows:

1. If the permittee is an owner or operator of a stationary CI internal combustion engine greater than 500 HP, the permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after changing emission-related settings in a way that is not permitted by the manufacturer. The permittee must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[45CSR16; 40 CFR §§60.4211(a), (c), (f), (g), and (g)(3)]

7.1.7. The permittee shall comply with the General Provisions of 40 CFR 60, specified in Table 8 of 40 CFR 60, Subpart IIII.
[45CSR16; 40 CFR §60.4218(a)]

7.1.8. In addition to S002 and S003, the permittee is authorized to construct and operate an additional fire pump engine/generator or multiple engines/generators (S058) not to exceed an aggregate mechanical boilerplate rating of 3,000 HP and to be fired only by diesel. The aggregate quantity of diesel fuel that shall be consumed in the additional engines shall not exceed 153.9 gallons per hour and 15,386 gallons per rolling twelve (12) month period during non-emergency use. The aggregate emissions from the additional fire pumps shall not exceed the following limits:

Emission Unit ID	Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
S058	Nitrogen Oxides	31.75	1.59
	Carbon Monoxide	17.26	0.86
	$PM_{2.5}/PM_{10}/PM^{(1)}$	0.99	0.05
	Volatile Organic Compounds	31.75	1.59

(1) Includes Condensables.

[45CSR13, R13-2896, Condition 8.1.3.]

7.1.9. The fire pump engine/generator or multiple engines/generators (S058) are each subject to all applicable regulations given under 40 CFR 60, Subpart IIII including the following:

a. Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 to Subpart IIII, for all pollutants.

Maximum Engine Power	Model Year(s)	NMHC + NO_X g/kW-hr (g/HP-hr)	CO g/kW-hr (g/HP-hr)	PM g/kW-hr (g/HP-hr)
kW > 560 (HP > 750)	2008+	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

[45CSR16; 40 CFR §60.4205(c) and Table 4 of 40 CFR 60, Subpart IIII; 45CSR13, R13-2896, Condition 8.1.5.]

7.1.10. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR §§60.4204 and 60.4205 for the entire life of the engine.
[45CSR16; 40 CFR §60.4206]

7.2. Monitoring Requirements

7.2.1. The permittee must install a non-resettable meter to monitor hours of operation.
[45CSR16; 40 CFR §60.4209(a)]

7.2.2. As the annual fuel usage limitations given under 7.1.1. and 7.1.8. above are based on the maximum hourly design capacity fuel usage rates and 100 hours of operation, compliance with the annual fuel usage limitations is based on compliance with 7.1.3.
[45CSR13, R13-2896, Condition 8.2.1.]

7.3. Testing Requirements

7.3.1. Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to 40 CFR 60, Subpart IIII must do so according to 40 CFR §§60.4212(a) through (e).
[45CSR16; 40 CFR §60.4212]

7.4. Recordkeeping Requirements

7.4.1. If the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
[45CSR16; 40 CFR §60.4214(b)]

7.5. Reporting Requirements

7.5.1. If an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in 40 CFR §60.4211(f)(3)(i), the permittee must submit an annual report according to the requirements in paragraphs a. through c. of this section.

a. The report must contain the following information:

i. Company name and address where the engine is located.

ii. Date of the report and beginning and ending dates of the reporting period.

iii. Engine site rating and model year.

iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

v. Hours spent for operation for the purposes specified in 40 CFR §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

b. The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

c. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to 40 CFR 60, Subpart IIII is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR §60.4. Beginning on February 26, 2025, submit annual report electronically according to 40 CFR §60.4214(g).

[45CSR16; 40 CFR §60.4214(d)]

7.5.2. If required to submit notifications or reports following the procedure specified in this paragraph, the permittee must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information claimed as CBI.
[45CSR16; 40 CFR §60.4214(g)]

7.6. Compliance Plan

7.6.1. None

8.0 Glycol Dehydration Units [emission unit ID(s): S006]

8.1. Limitations and Standards

8.1.1. The maximum aggregate wet natural gas throughput to Glycol Dehydration Unit S006 shall not exceed 460 mmscf/day or 167,900 mmscf/year.
[45CSR13, R13-2896, Condition 10.1.1.]

8.1.2. The maximum glycol recirculation rate in the Glycol Dehydration Unit (S006) shall not exceed 40 gallons per minute limit.
[45CSR13, R13-2896, Condition 10.1.2.]

8.1.3. The maximum aggregate controlled emissions generated from the Glycol Dehydration Unit (S006), including the still vent and the flash tank, but not including the combustion exhaust emissions from the Reboiler, shall not exceed the limits given in the following table:

a. Glycol Dehydration Unit S006:

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
VOCs	1.78	7.80
n-Hexane	*0.04*	*0.17*
Benzene	*0.03*	*0.13*
Toluene	*0.05*	*0.23*
Xylene	*0.03*	*0.13*
Total HAPs	0.15	0.66

(1) Emissions based on GLYCalc Version 4.0 using wet gas throughputs as limited under 8.1.1. and a 10% safety factor (on uncontrolled emissions).

[45CSR13, R13-2896, Condition 10.1.3.]

8.1.4. Still vent and flash tank vapors from S006 shall be routed to the Hot Oil Heater (S001: C001) and used as fuel.
[45CSR13, R13-2896, Condition 10.1.4.]

8.1.5. **40 CFR 63, Subpart HH: Exemptions**
Exemptions. The owner or operator of an area source is exempt from the requirements of 40 CFR §63.764(d) if the criteria listed in 40 CFR §§63.764(e)(1)(i) or (ii) are met, except that the records of the determination of these criteria must be maintained as required in 40 CFR §63.774(d)(1).

a. The actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere are less than 0.90 megagram per year, as determined by the procedures specified in 40 CFR §63.772(b)(2).

[45CSR13, R13-2896, Condition 10.1.5.; 45CSR34; 40 CFR §§63.764(e)(1) and (e)(1)(ii)]

8.1.6. The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph a. or b. of this condition. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

a. The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI-GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1); or

b. The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in 40 CFR §§63.772(a)(1)(i) or (ii), or an alternative method according to 40 CFR §63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

[45CSR34; 40 CFR §63.772(b)(2)]

8.1.7. Any source that determines it is not a major source but has actual emissions of 5 tons per year or more of a single HAP, or 12.5 tons per year or more of a combination of HAPs (i.e., 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination and each year thereafter, using gas composition data measured during the preceding 12 months.
[45CSR34; 40 CFR §63.760(c)]

8.1.8. At all times the owner or operator must 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
[45CSR34; 40 CFR §63.764(j)]

8.2. Monitoring Requirements

8.2.1. For the purposes of demonstrating compliance with the maximum wet gas throughput limit set forth in 8.1.1., the permittee shall monitor and maintain monthly and rolling twelve-month records of the wet gas throughput of the Glycol Dehydration Unit.
[45CSR13, R13-2896, Condition 10.2.1.]

8.2.2. Compliance with the Maximum Glycol Recirculation limitation set forth in 8.1.2. shall be determined using an average of a minimum of quarterly readings of the actual glycol pump(s) rate. If more than one pump is operating simultaneously then the rate of each operating pump shall be recorded and totaled for compliance purposes.
[45CSR13, R13-2896, Condition 10.2.2.]

8.2.3. Representative gas sample collection and analysis frequency for the dehydration unit shall be determined as set forth in the schedule provided in the following table:

Wet Gas Sampling and Analysis Frequency for Dehydration Units Based on Potential HAP Emission Rates	
Each dehydration unit exempt from §63.764(d) requirements and with federally enforceable controls	Upon request by the Secretary.
Each dehydration unit exempt from §63.764(d) requirements and without federally enforceable controls	An initial compliance evaluation within 180 days of registration issuance or within 180 days of startup of the dehydration unit, whichever is later.

[45CSR13, R13-2896, Condition 10.2.3.]

8.3. Testing Requirements

8.3.1. The permittee shall sample wet natural gas in accordance with the Gas Processor Association (GPA) Method 2166 and analyze the samples in accordance with GPA Method 2286. The permittee may utilize other equivalent methods provided they are approved in advance by DAQ as part of a testing protocol. If alternative methods are proposed, a test protocol shall be submitted for approval no later than 60 days before the scheduled test date.

Note: The DAQ defines a representative wet gas sample to be one that is characteristic of the average gas composition dehydrated throughout a calendar year. If an isolated sample is not indicative of the annual average composition, then a company may opt to produce a weighted average based on throughput between multiple sampling events, which can be used to define a more representative average annual gas composition profile.

[45CSR13, R13-2896, Condition 10.3.1.]

8.4. Recordkeeping Requirements

8.4.1. The permittee shall maintain records of the actual average benzene emissions (in terms of benzene emissions per year) as determined in accordance with 40 CFR §63.772(b)(2).
[45CSR34; 40 CFR §63.774(d)(1)(ii)]

8.5. Reporting Requirements

8.5.1. The TEG dehydration units are located at an area source and each meets the criteria in 40 CFR §63.764(e)(1)(ii). Therefore, the permittee is exempt from the reporting requirements for area sources specified in 40 CFR §§63.775(c)(1) through (7).
[45CSR34; 40 CFR §§63.775(c) and (c)(8)]

8.6. Compliance Plan

8.6.1. None

9.0 40 CFR 60, Subparts Kb and Kc Storage Tanks [emission unit ID(s): TK-802, TK-2802, TK-3802, TK-4802, TK-5802, TK-6802, TK-7802, VRU]

9.1. Limitations and Standards

9.1.1. Each of the Natural Gasoline Storage Tanks (TK-802, TK-2802, TK-3802, TK-4802, TK-5802, and TK-6802) will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from these tanks shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.
[45CSR13, R13-2896, Condition 12.1.1.]

9.1.2. The Refrigerated Propane Storage Tank (TK-7802) shall utilize the VRU to recapture propane product that flashes-off from the storage tank, re-condense the product, and then route it back to the storage tank.
[45CSR13, R13-2896, Condition 12.1.2.]

9.1.3. The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for each storage tank listed in this section.
[45CSR13, R13-2896, Condition 12.1.3.]

9.1.4. The Natural Gasoline Storage Tanks TK-802 and TK-2802 are subject to all applicable requirements of 40 CFR 60, Subpart Kb including the following:

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:
[45CSR16; 40 CFR §60.112b(a)]

1. A closed vent system and control device meeting the following specifications:

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in 40 CFR 60, Subpart VV, §60.485(b).
[45CSR16; 40 CFR §60.112b(a)(3)(i)]

ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (40 CFR §60.18) of the General Provisions.
[45CSR16; 40 CFR §60.112b(a)(3)(ii)]

[45CSR13, R13-2896, Condition 12.1.4.] (TK-802 and TK-2802)

9.1.5. The owner or operator of each source that is equipped with a closed vent system and control device as required in 40 CFR §60.112b(a)(3) or (b)(2) (other than a flare) is exempt from 40 CFR §60.8 of the General Provisions and shall meet the following requirements.

a. Submit for approval by the Administrator as an attachment to the notification required by 40 CFR §60.7(a)(1) or, if the facility is exempt from 40 CFR §60.7(a)(1), as an attachment to the notification required by 40 CFR §60.7(a)(2), an operating plan containing the information listed below.

1. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under 40 CFR 60, Subpart Kb, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816°C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

2. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

b. Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph a. of this condition, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

[45CSR16; 40 CFR §60.113b(c)] (TK-802 and TK-2802)

9.1.6. The Natural Gasoline Storage Tanks TK-3802 through TK-6802 and the Refrigerated Propane Storage Tank TK-7802 are subject to all applicable requirements of 40 CFR 60, Subpart Kc including the following:

a. All standards including emission limitations shall apply at all times, including periods of startup, shutdown, and malfunction. As provided in 40 CFR §60.11(f), 40 CFR §60.110c(g) supersedes the exemptions for periods of startup, shutdown, and malfunction in Subpart A of 40 CFR 60.
[45CSR16; 40 CFR §60.110c(g)] (TK-3802 through TK-7802)

b. **General storage vessel control requirements.** The permittee must equip and operate each storage vessel affected facility meeting the thresholds in 40 CFR §60.110c(c)(1) as specified in paragraphs b.1. and b.2. of this condition.

1. For TK-3802 to TK-6802, the permittee has elected to install and operate a closed vent system routed to a fuel gas system as specified in 40 CFR §60.112c(d).

2. For TK-7802, the permittee has elected to install and operate a closed vent system routed to a process as specified in 40 CFR §60.112c(d).

[45CSR16; 40 CFR §§60.112c(a) and (a)(1)] (TK-3802 through TK-7802)

c. For each storage vessel affected facility complying with the closed vent system routed to a control device, fuel gas system, or process provisions specified in 40 CFR §60.112(d) regardless of size and for

each storage vessel with a design capacity greater than or equal to 1,000,000 gallons containing a volatile organic liquid (VOL) that, as stored, has a maximum true vapor pressure equal to or greater than 1.5 psia, the permittee must comply with the requirements in 40 CFR §60.112c(e).
[45CSR16; 40 CFR §60.112c(a)(3)] (TK-3802 through TK-7802)

d. The permittee must meet the applicable testing, monitoring, and inspection requirements specified in 40 CFR §60.113c, recordkeeping requirements specified in 40 CFR §60.115c, and reporting requirements specified in 40 CFR §60.116c.
[45CSR16; 40 CFR §60.112c(a)(4)] (TK-3802 through TK-7802)

9.1.7. **Requirements for closed vent system routed to a fuel gas system or process.** The permittee must design, install, and operate each affected storage vessel with a closed vent system that routes to a fuel gas system or process as specified in paragraphs a. through c. of this condition.

a. The storage vessel must be designed and operated to be routed through a closed vent system to a fuel gas system or process at all times the storage vessel contains VOL without venting to the atmosphere through either meeting the storage vessel design requirements specified in paragraph a.1. of this condition or the vapor recovery system design requirements specified in paragraph a.2. of this condition. Compliance with this requirement must be demonstrated according to paragraph a.3. of this condition. Any vacuum breaking device on the storage vessel must close while the storage vessel is still under vacuum of at least -0.1 inches of water (-0.0036 psig or -0.025 kPa gauge).

1. The storage vessel must be designed to operate at a gauge pressure of no less than 1 psi greater than the maximum true vapor pressure of the stored liquid and any back pressure anticipated when the storage vessel is filled at its maximum rate without venting to the atmosphere.

2. The vapor recovery system must be designed and operated to maintain the pressure in each storage vessel routed to a control device below the venting pressure of that storage vessel.

3. The permittee must equip each pressure relief device and vacuum breaking device on a storage vessel with a device(s) or use a monitoring system that is capable of meeting the requirements in paragraphs a.3.i. through iii. of this condition. If all emissions from a pressure relief device are routed through a closed vent system to a control device, process, or fuel gas system, then the permittee is not required to comply with the requirements of this paragraph a.3.

i. Identifying the pressure release.

ii. Recording the time and duration of each pressure release.

iii. Notifying operators immediately that a pressure release is occurring. The device or monitoring system must be either specific to the pressure relief device or vacuum breaking device itself or must be associated with each storage vessel to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

b. Except for closed vent systems operated and maintained under negative pressure, each closed vent system must meet the requirements specified in paragraphs b.1. through 3. of this condition.

1. The closed vent system must be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 parts per million by volume (ppmv) above background, as determined using Method 21 of Appendix A-7 to 40 CFR 60 as specified in 40 CFR §§60.113c(c)(2) and (3), and as determined by observations for visible, audible, and olfactory indications of leaks. Visible, audible, and olfactory inspections must be performed quarterly and Method 21 of Appendix A-7 instrument monitoring must be conducted at least annually.

2. Except for pressure relief devices and except for open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR §§60.482-6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR §§60.482-6(a)(2), (b), and (c), the permittee must comply with the provisions of either paragraph b.2.i. or ii. of this condition for each closed vent system that contains bypass lines that could divert a vent stream to the atmosphere.

    i. Properly install, maintain, and operate a flow indicator that is capable of taking readings every 15 minutes. Install the flow indicator at the entrance to any bypass line.

    ii. Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration.

3. The permittee must equip each pressure relief device on a closed vent system with a device(s) or use a monitoring system that is capable of meeting the requirements in paragraphs b.3.i. through iii. If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, process, or fuel gas system, then the permittee is not required to comply with the requirements of this paragraph b.3.

    i. Identifying the pressure release.

    ii. Recording the time and duration of each pressure release.

    iii. Notifying operators immediately that a pressure release is occurring. The device or monitoring system must be either specific to the pressure relief device itself or must be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

c. If emissions are routed from a storage vessel to a fuel gas system or process, the permittee must meet the requirements in paragraphs c.1. through 4. of this condition, as applicable.

1. The fuel gas system or process must be operating at all times when emissions from an affected storage vessel are routed to it.

2. If all emissions are routed to a process, the VOL in the emissions must meet one or more of the conditions specified in paragraphs c.2.i. through iv. of this condition and the permittee must comply with the compliance determination requirements in paragraph c.3. of this condition.

i. Recycled and/or consumed in the same manner as a material that fulfills the same function in that process.

ii. Transformed by chemical reaction into materials that are not regulated materials.

iii. Incorporated into a product.

iv. Recovered.

3. To demonstrate compliance with paragraph c.2. of this condition for an affected storage vessel, the permittee must prepare a design evaluation (or engineering assessment) that demonstrates the extent to which one or more of the conditions specified in paragraphs c.2.i. through iv. of this are being met.

4. If emissions from an affected storage vessel are routed to a fuel gas system, the permittee must submit the statement of connection for fuel gas systems specified in 40 CFR §60.116c(a)(7).

[45CSR16; 40 CFR §§60.112c(d)(1), (d)(2), and (d)(6)] (TK-3802 through TK-7802)

9.1.8. **Requirements for storage vessel degassing.** For each storage vessel meeting the specifications in 40 CFR §60.112c(a)(3), the permittee must meet the requirements in paragraphs a. and b. of this condition during emptying and degassing of a storage vessel until the vapor space concentration in the storage vessel is less than 10 percent of the lower explosive limit (LEL) or, for nonflammable liquids, 5,000 ppmv as methane. The permittee must determine the LEL or methane concentration using process instrumentation or a portable measurement device and follow procedures for calibration and maintenance according to manufacturer's specifications. The permittee must check instrument calibration and check the instrumental offset response each day the instrument is used and prior to discontinuing controlled degassing to confirm the accuracy of the instrument's readings.

a. Remove liquids from the storage vessel as much as practicable. Chemicals or a diluent such as a distillate fuel may be introduced into the storage vessel for the purpose of reducing vapor concentration before or during active degassing.

b. Comply with the following:

1. Reduce total VOC emissions by routing emissions to a fuel gas system or process and meet the requirements specified in 40 CFR §60.112c(d)(6).

[45CSR16; 40 CFR §§60.112c(e), (e)(1), and (e)(2)(iii)] (TK-3802 through TK-7802)

9.2. Monitoring Requirements

9.2.1. To demonstrate compliance with section 9.1.3., the permittee shall monitor the vapor recovery unit system in accordance with the plans and specifications and manufacturer's recommendations.
[45CSR13, R13-2896, Condition 12.2.1.]

9.2.2. For each storage vessel subject to the provision in 40 CFR §60.112c(a), the permittee must meet the requirements of paragraph a. of this condition if emissions are routed through a closed vent system to a fuel

gas system or process. The permittee must also meet the applicable requirements of paragraph b. of this condition.

a. **Monitoring of the closed vent system**. For each source that is equipped with a closed vent system and routes to a fuel gas system or process to meet the requirements in 40 CFR §60.112c(d), the permittee must conduct monitoring and inspections of the closed vent system as specified in paragraph a.1. of this condition and repair leaks as specified in paragraph a.2. of this condition.

1. For each closed vent system, the permittee must conduct the instrument monitoring in paragraphs a.1.i. through iii. of this condition. The permittee must conduct the initial instrument monitoring within 180 days of an affected facility being connected to the closed vent system. Subsequent instrument inspections must be conducted within 365 days of the previous inspection. Visual, audible, and olfactory inspections must be conducted quarterly.

i. Conduct instrument monitoring using the procedures in Method 21 of Appendix A-7 to 40 CFR 60. The detection instrument must meet the performance criteria of Method 21 of Appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 of Appendix A-7 must be for the average composition of the fluid and not for each individual organic compound in the stream. For streams that contain nitrogen, air, water, or other inerts that are not organic VOC, the representative stream response factor must be determined on an inert-free basis. The instrument reading that defines a leak is 500 ppmv (as methane). The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of Appendix A-7. The calibration gases in paragraph a.1.i.a. and b. of this condition must be used. The drift assessment specified in paragraph a.1.i.c. of this condition must be performed at the end of each monitoring day.

a. Zero air (less than 10 ppm of hydrocarbon in air).

b. A mixture of methane in air at a concentration of approximately 500 ppmv.

c. At the end of each monitoring day, check the instrument using the same calibration gas that was used to calibrate the instrument before use. Follow the procedures specified in Method 21 of Appendix A-7 to 40 CFR 60, section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. If multiple scales are used, record the instrument reading for each scale used. Divide the arithmetic difference of the initial and post-test calibration response by the corresponding calibration gas value for each scale and multiply by 100 to express the calibration drift as a percentage. If a calibration drift assessment shows a negative drift of more than 10 percent, then re-monitor all equipment monitored since the last calibration with instrument readings between the leak definition and the leak definition multiplied by (100 minus the percent of negative drift) divided by 100. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment with instrument readings above the leak definition and below the leak definition multiplied by (100 plus the percent of positive drift) divided by 100 monitored since the last calibration may be re-monitored.

ii. Any parts of the closed vent system that are designated as unsafe to inspect are exempt from the inspection requirements of paragraph a.1.i. of this section if the conditions of paragraph a.1.ii.a. and b. of this condition are met.

a. The owner or operator determines that the equipment is unsafe-to-inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraph a.1.i. of this condition; and

b. The owner or operator has a written plan that requires inspection of the equipment as frequently as practical during safe-to-inspect times. Inspection is not required more than once annually.

iii. Any parts of the closed vent system that are designated as difficult-to-inspect are exempt from the inspection requirements of paragraph a.1.i. of this section if the provisions of paragraphs a.1.iii.a. and b. apply.

a. The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters (7 feet) above a support surface; and

b. The owner or operator has a written plan that requires inspection of the equipment at least once every 60 calendar months.

2. Leaks, as indicated by an instrument reading greater than 500 ppmv or emissions detected by visible, audible, and olfactory methods, shall be repaired as soon as practical following the requirements outlined in paragraphs a.2.i. and ii. of this condition.

i. Except as allowed by paragraph a.2.ii. of this condition, a first attempt at repair shall be made no later than 5 days after the leak is detected. Repairs shall be completed no later than 15 days after the leak is detected or at the beginning of the next introduction of vapors to the system, whichever is later.

ii. Delay of repair of a closed vent system for which leaks have been detected is allowed if repair within 15 days after a leak is detected is technically infeasible or unsafe or if the owner or operator determines that emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed as soon as practical.

b. **Requirements for determining maximum true vapor pressure.** For each affected storage vessel, the permittee must determine the maximum true vapor pressure of the stored VOL according to the requirements specified in paragraphs b.1. and 2. of this condition. For storage vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For storage vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

1. Prior to the initial filling of the storage vessel or to the refilling of the storage vessel with a new VOL, the highest maximum true vapor pressure for the range of anticipated liquids to be stored, including mixtures for which the permittee can define the range of concentrations for constituents in the mixture or with a known maximum Reid vapor pressure, must be determined using any one of the methods described in paragraphs b.1.i. through iv. of this condition.

i. As obtained from standard reference texts.

ii. ASTM D6377-20 (incorporated by reference; see 40 CFR §60.17). Perform the method using a vapor-to-liquid ratio of 4:1, which is expressed in the method as VPCR.

iii. ASTM D6378-22 (incorporated by reference; see 40 CFR §60.17). Perform the method using a vapor-to-liquid ratio of 4:1.

iv. As measured by an appropriate method as approved by the Administrator.

2. For each affected storage vessel storing a mixture of indeterminate composition or a mixture of unknown variable composition, the initial determination of the vapor pressure required by paragraph b.1. of this condition must be a physical test using one of the methods specified in paragraphs b.1.ii. through iv. of this condition. Additional physical tests using one of the methods specified in paragraphs b.1.ii. through iv. of this condition are required at least once every 6 calendar months thereafter as long as the measured vapor pressure remains below the applicable thresholds in 40 CFR §§60.110c(c)(1), (c)(2), (d)(1), or (d)(2). If the vapor pressure measured under this paragraph b.2. exceeds the threshold defined in 40 CFR §60.110c(c)(1), (c)(2), (d)(1), or (d)(2), the permittee must meet the requirements in 40 CFR §60.112c and the corresponding requirements in 40 CFR §§60.113c through 60.116c. If the storage vessel does not have controls meeting the requirements in 40 CFR §60.112c, the storage vessel must be emptied and taken out of service until controls meeting the requirements in 40 CFR §60.112c can be installed. Upon compliance with the provisions in 40 CFR §60.112c, no additional vapor pressure monitoring is required.

[45CSR16; 40 CFR §§60.113c(c), (c)(2), (c)(3), and (d)] (TK-3802 through TK-7802)

9.3. Testing Requirements

9.3.1. None

9.4. Recordkeeping Requirements

9.4.1. **Record of Maintenance of Vapor Recovery Unit.** The permittee shall maintain accurate records of the vapor recovery unit equipment inspection and/or preventative maintenance procedures.
[45CSR13, R13-2896, Condition 12.3.1.]

9.4.2. **Record of Malfunction of Vapor Recovery Unit.** The permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the vapor recovery unit during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

[45CSR13, R13-2896, Condition 12.3.2.]

9.4.3. After installing control equipment in accordance with 40 CFR §§60.112b(a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

The permittee shall keep copies of all records required by this section, except for the record required by 9.4.3.a., for at least two years. The record required by 9.4.3.a. will be kept for the life of the control equipment.

a. A copy of the operating plan.

b. A record of the measured values of the parameters monitored in accordance with 40 CFR §60.113b(c)(2).

[45CSR16; 40 CFR §§60.115b and 60.115b(c)] (TK-802 and TK-2802)

9.4.4. The permittee must comply with the following recordkeeping requirements:

a. The permittee shall keep copies of all records required by 40 CFR 60, Subpart Kb, except for the record required by 9.4.4.b., for at least 2 years. The record required by 9.4.4.b. will be kept for the life of the source.

b. The owner or operator of each storage vessel as specified in 40 CFR §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

[45CSR16; 40 CFR §§60.116b(a) and (b)] (TK-802 and TK-2802)

9.4.5. **Recordkeeping requirements under 40 CFR 60, Subpart Kc**

a. Except as otherwise specified in paragraphs b. through d. of this condition, the permittee must keep copies of all records required by 40 CFR §60.115c and all reports required under 40 CFR §60.116c for at least 5 years.

b. For each storage vessel affected facility as specified in 40 CFR §60.110c(a), the permittee must keep readily accessible records for the life of the source showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

c. Each vessel equipped with a closed vent system routed to a control device, fuel gas system, or process meeting the specification of 40 CFR §60.112c(d) is exempt from the requirements of 40 CFR §60.115c(c).

d. For each storage vessel as specified in 40 CFR §60.112c(a), the permittee must keep records as required in 40 CFR §§60.115c(d)(1) through (5), as applicable depending upon the control equipment installed to meet the requirements of 40 CFR §60.112c.

1. After installing a closed vent system routed to a fuel gas system or process to comply with the provisions in 40 CFR §60.112c(d), the permittee must keep the following records, as well as the records in 40 CFR §§60.115c(d)(4) and (5), as applicable.

i. Monitoring for the closed vent system conducted under 40 CFR §60.113c(c)(2), including the date of inspection.

ii. The written plan(s) required under 40 CFR §§60.113c(c)(2)(ii) and (iii) for unsafe-to-inspect and difficult-to-inspect portions of the closed vent system.

iii. For each leak detected during the monitoring conducted under 40 CFR §§60.113c(c)(2) and (3), the permittee must record: the date the leak was detected; the location of the leak; the method used to detect the leak (Method 21 of Appendix A-7 to 40 CFR 60 or visible, audible, and olfactory methods); and the maximum concentration reading obtained by Method 21 of Appendix A-7, if applicable. For each repair attempt, the permittee must record: the date of each repair attempt; the actions taken to repair the leak during each repair attempt; and date the repair was completed. If the repair is delayed, the permittee must record the reason for the delay and the date the repair is expected to be completed.

iv. For each bypass line, maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out.

v. For each pressure relief device or vacuum breaking device on a storage vessel or closed vent system required to be monitored according to 40 CFR §60.112c(d)(1)(iii) or (d)(2)(iii): the device type; the monitoring device or system used for the device; data from the device or system indicating whether a pressure release occurred; and the date, time, and duration of each pressure release, if applicable.

e. For storage vessels required to meet the degassing requirements in 40 CFR §60.112c(a)(3), the permittee must maintain records necessary to demonstrate compliance with the requirements in 40 CFR §60.112c(e) including, if appropriate, records of existing standard site procedures used to empty and degas (deinventory) equipment for safety purposes.

[45CSR16; 40 CFR §§60.115c(a), (b), (c)(2), (d), (d)(3), (d)(3)(iii) to (vii), and (e)] (TK-3802 through TK-7802)

9.5. Reporting Requirements

9.5.1. Upon request by the Director, the permittee shall report deviations within a requested time from any occurrences when the control device was operated outside of the parameters defined in the monitoring plan. **[45CSR13, R13-2896, Condition 12.3.3.]**

9.5.2. **Initial notification requirements for 40 CFR 60, Subpart Kc.** The permittee must submit initial notifications to the Administrator within 60 days after becoming an affected storage vessel, whichever is later. Once the report template for 40 CFR 60, Subpart Kc has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, the permittee must submit all subsequent initial notifications using the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart Kc and following the procedure specified in 40 CFR §60.116c(f). The date report templates become available will be listed on the CEDRI website. For each storage vessel affected facility subject to the standards in 40 CFR §60.112c, include the following information in the initial notification:

a. The following general facility information:

1. Facility name;

2. Facility physical address, including city, county, state, and zip code.

3. Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places; and

4. The following information for the facility contact person:

i. Name;

ii. Mailing address, including city, county, state, and zip code;

iii. Telephone number; and

iv. Email address.

b. Identification of the storage vessel(s) subject to 40 CFR 60, Subpart Kc.

c. Capacity (in gallons) of each storage vessel.

d. Maximum true vapor pressure of the liquid stored (in psia) in each storage vessel.

e. Indication of the standards for which the storage vessel complies [40 CFR §§60.112c(b); 60.112c(c); 60.112c(d); 60.112c(e)].

f. If emissions are routed to a process, submit the information specified in 40 CFR §§60.112c(d)(6)(ii) and (iii).

g. If emissions are routed to a fuel gas system, as specified in 40 CFR §60.112c(d)(6)(iv), submit a statement that the emission stream is connected to the fuel gas system.

[45CSR16; 40 CFR §§60.116c(a), (a)(1) to (a)(5), (a)(7), and (a)(8)] (TK-3802 through TK-7802)

9.5.3. **Reporting requirements for semiannual reports under 40 CFR 60, Subpart Kc.**

a. **Semiannual reports under 40 CFR 60, Subpart Kc.** The permittee must submit to the Administrator semiannual reports with the applicable information in 40 CFR §§60.116c(c)(1) through (12) by the dates specified in 40 CFR §60.116c(d). For 40 CFR 60, Subpart Kc, the semiannual reports supersede the excess emissions and monitoring systems performance report and/or summary report form required under 40 CFR §60.7. Once the report template for 40 CFR 60, Subpart Kc has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for 1 year, the permittee must submit all subsequent reports using the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart Kc and following the procedure specified in 40 CFR §60.116c(f). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in 40 CFR 60, Subpart Kc, regardless of the method in which the report is submitted.

1. Report the following general facility information:

i. Facility name;

ii. Facility physical address, including city, county, and state;

iii. Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places;

iv. The following information for the facility contact person:

a. Name;

b. Mailing address;

c. Telephone number; and

d. Email address.

v. Date of report and beginning and ending dates of the reporting period. The permittee is no longer required to provide the date of report when the report is submitted via CEDRI; and

vi. Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

2. After installing a closed vent system that routes to a fuel gas system, or process to comply with 40 CFR §60.112c, report the following.

i. For each inspection conducted under 40 CFR §60.113c(c)(2), identification of the closed vent system, the date of inspection, the type of inspection (Method 21 of Appendix A-7 to 40 CFR 60 or visible, audible, and olfactory methods) and summary result of the inspection (no leaks detected or leaks were detected). For each leak detected, provide an identification of the part

of the closed vent system associated with the leak, the date of the first attempt at repair, and the date of successful repair or anticipated repair if the repair is delayed.

ii. The start date and time, duration in hours, and an estimate of the mass quantity in pounds of VOL released for times when flow is detected or emissions are diverted from the control device through a bypass line while a storage vessel affected facility vented to the closed vent system contains VOL or is being degassed.

3. For pressure relief devices on a storage vessel or closed vent system subject to 40 CFR §60.112c(d)(1)(iii) or (d)(2)(iii), report each pressure release to the atmosphere, including pressure relief device identification name or number, the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released.

4. For vacuum breaking devices on a storage vessel subject to 40 CFR §§60.112c(d) and (d)(1)(iii), report the following information for each time the vacuum breaking device failed to close prior to the storage vessel reaching atmospheric pressure: identification name or number of vacuum breaking device; the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of VOL released.

b. **Timeframe for semiannual report submissions.**

1. The first semiannual report will cover the period starting with the date the source becomes an affected facility subject to 40 CFR 60, Subpart Kc and ending June 30 or December 31, whichever date is earlier. For example, if the source becomes an affected facility on April 15, the first semiannual report would cover the period from April 15 to June 30. The first semiannual report must be submitted on or before the last day of the month 2 months after the last date covered by the semiannual report. In this example, the first semiannual report would be due August 31.

2. Subsequent semiannual reports will cover subsequent 6 calendar month periods (January 1 through June 30 or July 1 through December 31, as applicable) with each report due on or before the last day of the month 2 months after the last date covered by the semiannual report (August 31 or February 28 or 29, as applicable).

3. For each affected facility that is subject to permitting regulations pursuant to 40 CFR 70 or 71, if the delegated authority has established dates for submitting semiannual reports pursuant to 40 CFR §70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent semiannual reports according to the dates the delegated authority has established instead of the dates in paragraphs b.1. and 2. of this condition.

[45CSR16; 40 CFR §§60.116c(c), (c)(1), (c)(8), (c)(8)(ii), (c)(8)(iii), (c)(11), (c)(12), and (d)] (TK-3802 through TK-7802)

9.5.4. **Requirements for electronically submitting reports under 40 CFR 60, Subpart Kc.** For notifications or reports that must be submitted following the procedures specified in 40 CFR §60.116c(f), the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information claimed as confidential business information (CBI).
[45CSR16; 40 CFR §60.116c(f)]

9.6. Compliance Plan

9.6.1. None

10.0 Flare [emission unit ID(s): S004A]

10.1. Limitations and Standards

10.1.1. The permittee shall utilize a non-assisted Callidus CAL-MP staged, multi-point ground flare system (with a maximum aggregate pilot light heat input of 1.629 MMBtu/hr), designated as S004A, for control of potential emissions from maintenance events, equipment blowdowns, pressure relief valves, and other controlled sources. The flare shall have a maximum design capacity of 19.8 mmscf/hr.
[45CSR13, R13-2896, Condition 13.1.1.]

10.1.2. The Flare (S004A) shall operate according to the following requirements:

a. Maximum aggregate combustion exhaust emissions (not including uncombusted pass-through emissions of VOCs) from operation of the Flare (including those contributed by the pilot light) shall not exceed the following during routine maintenance events, equipment blowdowns, from pressure relief valves, and other controlled sources:

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
Nitrogen Oxides	1,539.61	14.61
Carbon Monoxide	3,073.64	29.17
$PM_{2.5}/PM_{10}/PM^{(1)}$	30.66	0.50
VOCs	22.19	0.36

(1) Compliance with this limit will ensure compliance with 45CSR§6-4.1 (Condition 10.1.4.a.).

b. Based on the minimum VOC destruction and removal efficiency (DRE) of 98.0% as given under 10.1.6., maximum emissions of uncombusted pass-through VOCs and HAPs (generated during routine maintenance events, equipment blowdowns, and from pressure relief valves) emitted at the Flare (as uncombusted pass-through emissions) shall not exceed 10,153 lb/hr and 39.38 ton/year of VOCs and 4.53 lb/hr and 0.12 ton/year of HAPs.

[45CSR13, R13-2896, Condition 13.1.2.]

10.1.3. The total heat input of waste gases sent to the Flare during routine pigging events, equipment and site-wide blowdowns, the ethane treater flash tanks, irregular process vents, and from the closed vent system shall not exceed 197,459 MMBtu per rolling twelve-month period.
[45CSR13, R13-2896, Condition 13.1.3.]

10.1.4. The Flare is subject to 45CSR6. The requirements of 45CSR6 include but are not limited to the following:

a. No person shall cause, suffer, allow or permit particulate matter to be discharged from any incinerator into the open air in excess of the quantity determined by use of the following formula:

$$Emissions\ (lb/hr) = F \times Incinerator\ Capacity\ (ton/hr)$$

Where, the factor, F, is either 5.43 for an incinerator with a capacity of less than 15,000 lb/hr or 2.72 for an incinerator with a capacity of 15,000 lb/hr or greater.

[45CSR§6-4.1.]

b. No person shall cause, suffer, allow or permit emission of smoke into the atmosphere from any incinerator which is twenty (20%) percent opacity or greater.
[45CSR§6-4.3.]

c. The provisions of 45CSR§6-4.3. shall not apply to smoke which is less than forty percent (40%) opacity, for a period or periods aggregating no more than eight (8) minutes per start-up, or six (6) minutes in any sixty (60)-minute period for stoking operations.
[45CSR§6-4.4.]

d. No person shall cause or allow the emission of particles of unburned or partially burned refuse or ash from any incinerator which are large enough to be individually distinguished in the open air.
[45CSR§6-4.5.]

e. Incinerators, including all associated equipment and grounds, shall be designed, operated and maintained so as to prevent the emission of objectionable odors.
[45CSR§6-4.6.]

f. At such reasonable times as the Secretary may designate, the operator of any incinerator shall be required to conduct or have conducted stack tests to determine the particulate matter loading, by using 40 CFR 60, Appendix A, Method 5 or other equivalent U.S. EPA approved method approved by the Secretary, in exhaust gases. Such tests shall be conducted in such manner as the Secretary may specify and be filed on forms and in a manner acceptable to the Secretary. The Secretary may, at the Secretary's option, witness or conduct such stack tests. Should the Secretary exercise his or her option to conduct such tests, the operator will provide all the necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment such as scaffolding, railings and ladders to comply with generally accepted good safety practices.
[45CSR§6-7.1.]

g. The Secretary may conduct such other tests as the Secretary may deem necessary to evaluate air pollution emissions other than those noted above.
[45CSR§6-7.2.]

[45CSR13, R13-2896, Condition 13.1.4.]

10.1.5. A pilot flame must be present at all times of operation of the Flare. The presence of a pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
[45CSR13, R13-2896, Condition 13.1.5.]

10.1.6. The Flare shall be operated and designed in accordance with the information filed in permit application R13-2896F to achieve a VOC DRE of 98.0%.
[45CSR13, R13-2896, Condition 13.1.7.]

10.1.7. The inlet gas flow rate of the Flare must be equal to or less than the maximum specified by the manufacturer.
[45CSR13, R13-2896, Condition 13.1.8.]

10.2. Monitoring Requirements

10.2.1. In order to demonstrate compliance with the requirements of 10.1.2., 10.1.3., and 10.1.4.a., the permittee shall monitor the aggregate throughput and heat input of waste gases sent to the Flare on a monthly basis.
[45CSR13, R13-2896, Condition 13.2.1.]

10.2.2. To demonstrate compliance with the emission limits of 10.1.2. and the flame requirements of 10.1.5., the presence of a flame shall be continuously monitored using a duplex thermocouple or any other equivalent device to detect the presence of a flame. The presence or absence of the flame shall be recorded in the facility's data acquisition system at 15-minute intervals. The absence of the pilot flame shall be defined as an excursion per the CAM Plan under 40 CFR Part 64.
[45CSR13, R13-2896, Condition 13.2.2.; 45CSR§30-5.1.c.; 40 CFR §64.6(c)]

10.2.3. The permittee shall meet the following Visible Emissions Requirements for the Ground Flare:

a. To demonstrate compliance with the visible emissions requirements of 45CSR6, the permittee shall conduct the following visible emission checks and/or opacity monitoring and recordkeeping for the Ground Flare:

1. The visible emission check shall determine the presence or absence of visible emissions. The observations shall be conducted according to Section 11 of EPA Method 22. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training may be obtained from written materials found in the References 1 and 2 from 40 CFR 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR 60, Appendix A, Method 9 certification course. The observation period (Section 11 of EPA Method 22) shall be a minimum of one (1) hour each calendar month during flaring operation;

2. As the Ground Flare is of smokeless design, any observation of visible emissions will indicate incorrect operation of the flare. Therefore, upon the observation of visible emissions, the permittee shall, at the next available safe opportunity, cease operation of the flare and attempt to correct the problem. After an attempt to correct the problem, the permittee shall then conduct a minimum of one (1) hour of visible emissions observations according to 10.2.3.a. during the flare operation;

3. The permittee shall maintain records of all monitoring data required by 10.2.3. documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s);

4. Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40 CFR 60, Appendix A, Method 9 or 22 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned.

[45CSR13, R13-2896, Condition 13.2.3.]

10.2.4. **Proper maintenance.** At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[45CSR§30-5.1.c.; 40 CFR §64.7(b)]

10.2.5. **Continued operation.** Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of 40 CFR Part 64, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[45CSR§30-5.1.c.; 40 CFR §64.7(c)]

10.2.6. **Response to excursions or exceedances.**

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[45CSR§30-5.1.c.; 40 CFR §64.7(d)]

10.2.7. **Documentation of need for improved monitoring.** After approval of monitoring under 40 CFR Part 64, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for

which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the part 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[45CSR§30-5.1.c.; 40 CFR §64.7(e)]

10.2.8. **Quality Improvement Plan (QIP) Requirements.** Based on the results of a determination made under 40 CFR §64.7(d)(2), the Administrator or the permitting authority may require the permittee to develop and implement a QIP. If required, the QIP shall be developed and implemented in accordance with 40 CFR §§64.8(b) through (e).
[45CSR§30-5.1.c.; 40 CFR §64.8]

10.3. Testing Requirements

10.3.1. None

10.4. Recordkeeping Requirements

10.4.1. For the purpose of demonstrating compliance with Sections 10.1.5. and 10.2.2., the permittee shall maintain records of the times and duration of all periods which the pilot flame was absent.
[45CSR13, R13-2896, Condition 13.2.4.]

10.4.2. **General recordkeeping requirements.**

a. The owner or operator shall comply with the recordkeeping requirements specified in 40 CFR §70.6(a)(3)(ii). The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 CFR §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 CFR Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[45CSR§30-5.1.c.; 40 CFR §64.9(b)]

10.5. Reporting Requirements

10.5.1. If the permittee is required by the Director to demonstrate compliance with sections 10.1.4.f. and 10.1.4.g., then the permittee shall submit a testing protocol at least thirty (30) days prior to testing and shall submit a notification of the testing date at least fifteen (15) days prior to testing. The permittee shall submit the testing results within sixty (60) days of testing and provide all supporting calculations and testing data.
[45CSR13, R13-2896, Condition 13.2.5.]

10.5.2. Any deviation(s) from the flare design and operation criteria in Section 10.1.6. and permit application R13-2896F, shall be reported in writing to the Director as soon as practicable, but no later than ten (10) calendar days following discovery of such deviation.
[45CSR13, R13-2896, Condition 13.2.6.]

10.5.3. The permittee shall report to the Director, the time, cause of event, estimate of emissions and corrective actions taken when the Ground Flare was used for an emergency at the facility.
[45CSR13, R13-2896, Condition 13.2.7.]

10.5.4. **General reporting requirements.**

a. On and after the date specified in 40 CFR §64.7(a) by which the owner or operator must use monitoring that meets the requirements of 40 CFR Part 64, the owner or operator shall submit monitoring reports to the permitting authority in accordance with 40 CFR §70.6(a)(3)(iii).

b. A report for monitoring under 40 CFR Part 64 shall include, at a minimum, the information required under 40 CFR §70.6(a)(3)(iii) and the following information, as applicable:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

3. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[45CSR§30-5.1.c.; 40 CFR §64.9(a)]

10.6. Compliance Plan

10.6.1. None

11.0 Ethane Amine Units [emission unit ID(s): S011, S054]

11.1. Limitations and Standards

11.1.1. **Maximum Throughput Limitation.** The maximum sour ethane throughput to each individual Ethane Amine Unit shall not exceed 129 mmscf/day and 47,085 mmscf/year (or, alternatively 81,523 barrels/day and 29,755,895 barrels/year of treated ethane). Compliance with the Maximum Throughput Limitation shall be determined using a twelve-month rolling total. A twelve-month rolling total shall mean the sum of the monthly throughput at any given time during the previous twelve consecutive calendar months.
[45CSR13, R13-2896, Condition 14.1.1.]

11.1.2. Each Ethane Amine Unit (S011, S054) shall be designed and operated in accordance with the following:

a. Carbon dioxide will be removed from the ethane product in an amine contacting system;

b. The total ethane product shall be contacted with an amine solution in the Amine Contactor where the carbon dioxide in the ethane product is removed to less than 500 ppmw;

c. The rich amine from the Contactor is regenerated in the Amine Regenerator where heat input is used to drive the carbon dioxide and water overhead. Overheads from S011 are vented to the atmosphere and overheads from S054 are routed as described in Condition 11.1.15.; and

d. The lean amine from the bottom of the Regenerator is recycled back to the Amine Contactor.

[45CSR13, R13-2896, Condition 14.1.2.]

11.1.3. Off gas from both Ethane Amine Units' flash tanks shall be collected and sent to the Ground Flare (S004A) for combustion.
[45CSR13, R13-2896, Condition 14.1.3.]

11.1.4. Maximum methanol and VOC emissions from Ethane Amine Unit S011 shall not exceed 1.82 lb/hr and 7.99 ton/year, and 1.98 lb/hr and 8.67 ton/year, respectively.
[45CSR13, R13-2896, Condition 14.1.4.]

11.1.5. The still vent emissions from S054 shall be, at a minimum of 95% of time the unit is in operation, captured by the vapor recovery unit (VRU) and routed to the residue gas discharge line. During VRU downtime, emissions from S054 still vent shall vent to atmosphere. Maximum methanol and VOC emissions from Ethane Amine Unit S054 shall not exceed 1.82 lb/hr and 0.40 ton/year, and 1.98 lb/hr and 0.43 ton/year, respectively.
[45CSR13, R13-2896, Condition 14.1.5.]

11.2. Monitoring Requirements

11.2.1. In order to show compliance with 11.1.1., the permittee shall either: (1) monitor and record the monthly and twelve-month total throughput of sour ethane fed to both Ethane Amine Units, or (2) monitor and record the monthly and twelve-month total throughput of total treated ethane from both Ethane Amine Units.
[45CSR13, R13-2896, Condition 14.2.1.]

11.2.2. The permittee shall monitor and record the monthly and twelve-month total percentage of time Ethane Amine Unit S054 is operated when the VRU is not in operation.
[45CSR13, R13-2896, Condition 14.2.2.]

11.3. Testing Requirements

11.3.1. The permittee shall conduct, at a minimum of once per twelve-month period, sampling of the inlet gas stream to the Ethane Amine Units. The results of this test shall be used, with appropriate modeling techniques (such as use of ProMax software), to verify that the emissions of the unit are in compliance with those given under 11.1.4. and 11.1.5. above.
[45CSR13, R13-2896, Condition 14.2.3.]

11.4. Recordkeeping Requirements

11.4.1. None

11.5. Reporting Requirements

11.5.1. None

11.6. Compliance Plan

11.6.1. None

12.0 Other Storage Tanks and Liquids Loading/Unloading [emission unit ID(s): TK-906, TK-2906, TK-907, TK-2907, S008, S015, S033, S055, L-1]

12.1. Limitations and Standards

12.1.1. The maximum design capacity of material loading/unloading and maximum associated emissions shall not exceed the following for the specific NGLs:

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)	VOC Emissions	
					lb/hr	ton/year
S008	Propane	3,600 (vb)	4,000 (vb)	4,000 (vb)	5.99	4.21
	Isobutane			No		
	Butanes			No		
	NGL			No		
	Natural Gasoline	600 (vb)	2,000 (vb)	N/A		
S033	Natural Gasoline	N/A	N/A	4,000	97.22	82.69
S015	Slop Oil/Produced Water	150	No	No	2.32	0.11
L-1	Gasoline Dispenser	20 (gal/hr)	No	No	0.18	0.072
S055	Pressurized NGL/Condensate (Unloading)	3,600	N/A	No	6.64	14.54

[45CSR13, R13-2896, Condition 15.1.1.]

12.1.2. The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.
[45CSR13, R13-2896, Condition 15.1.2.]

12.1.3. The main Liquids Loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutane, butanes, natural gasoline, or NGLs to truck or railcar ***and*** when loading propane to barge. Natural Gasoline barge loading (S033) operations, and Slop Oil/Produced Water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.
[45CSR13, R13-2896, Condition 15.1.3.]

12.1.4. All truck loading of Slop Oil and Produced Water shall be done using the submerged-fill method. The "submerged-fill method" shall, for the purposes of this permit, mean either bottom-filling or filling by extending the pipe to near the bottom of the tank, and as soon as is practicable, below the level of liquid.
[45CSR13, R13-2896, Condition 15.1.4.]

12.1.5. The maximum annual throughput and VOC emissions for the specified tanks shall not exceed what is given in the following table:

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-L-1	Gasoline(1)	12,000	0.13
TK-906	Slop Oil	248,712	0.05
TK-907	Produced Water	754,824	0.14
TK-2906	Slop Oil	248,712	0.05
TK-2907	Produced Water	754,824	0.14

(1) This is purchased retail gasoline, not natural gasoline as produced on site.

[45CSR13, R13-2896, Condition 15.1.5.]

12.2. Monitoring Requirements

12.2.1. None

12.3. Testing Requirements

12.3.1. None

12.4. Recordkeeping Requirements

12.4.1. To demonstrate compliance with sections 12.1.2. and 12.1.5., the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas (S008, S033, S055) and in the specified storage tanks.
[45CSR13, R13-2896, Condition 15.2.1.]

12.5. Reporting Requirements

12.5.1. None

12.6. Compliance Plan

12.6.1. None

13.0 Pigging Operations [emission unit ID(s): S034, S035]

13.1. Limitations and Standards

13.1.1. The permittee shall utilize a non-assisted flare, designated as S034, for control of potential emissions during all times of propane pig trap operations. The flare will have a maximum design capacity of 72,000 scf/hr and be designed and operated to achieve a minimum propane DRE of 98%.
[45CSR13, R13-2896, Condition 16.1.1.]

13.1.2. The maximum annual combustion of waste gases in the pig trap flare (S034) shall not exceed 720,000 scf. The maximum number of pigging events per year for all pig traps shall not exceed the limits and volumes per event (scf) established in the permit application R13-2896G.
[45CSR13, R13-2896, Condition 16.1.2.]

13.1.3. Maximum combustion exhaust emissions (not including uncombusted pass-through emissions of waste gases) from S034 shall not exceed the following:

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/year)
Nitrogen Oxides	24.25	0.12
Carbon Monoxide	13.99	0.07
$PM_{2.5}/PM_{10}/PM$	1.31	0.01

[45CSR13, R13-2896, Condition 16.1.3.]

13.1.4. Based on the minimum VOC DRE of 98.0% as required under 13.1.1., maximum emissions of uncombusted VOCs emitted at the Pigging Flare shall not exceed 227.77 lb/hr and 1.14 ton/year of VOCs. The maximum emissions of VOCs and HAPs emitted from all other pigging operations with the exception of the propane pig trap shall not exceed 103.10 lb/hr and 0.84 ton/year, and 1.25 lb/hr and 0.01 ton/year, respectively.
[45CSR13, R13-2896, Condition 16.1.4.]

13.1.5. The Pigging Flare shall be designed and operated in accordance with 40 CFR §60.18.
[45CSR13, R13-2896, Condition 16.1.6.]

13.1.6. The Pigging Flare is subject to 45CSR6. The requirements of 45CSR6 include but are not limited to those given under condition 10.1.4.
[45CSR13, R13-2896, Condition 16.1.7.]

13.1.7. The pigging vapors from the three (3) truck side 30” Inlet Receivers shall be captured by the VRU and routed back to the process.
[45CSR13, R13-2896, Condition 16.1.5.]

13.2. Monitoring Requirements

13.2.1. In order to show compliance with 13.1.2., the permittee shall calculate, based on the information collected under 13.2.2., the throughput (in scf) of waste gases fed to S034 on a monthly and a rolling twelve-month basis.
[45CSR13, R13-2896, Condition 16.2.1.]

13.2.2. In order to show compliance with 13.1.2., the permittee shall monitor and record the total number and type of pigging events and the estimated volume per event (in scf) on a monthly and rolling twelve-month total for all pig traps.
[45CSR13, R13-2896, Condition 16.2.2.]

13.2.3. The permittee shall meet the following Visible Emissions Requirements for the S034:

a. To demonstrate compliance with the visible emissions requirements of 45CSR6, the permittee shall conduct the following visible emission checks and/or opacity monitoring and recordkeeping for the Pigging Flare:

1. The visible emission check shall determine the presence or absence of visible emissions. The observations shall be conducted according to Section 11 of EPA Method 22. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training may be obtained from written materials found in the References 1 and 2 from 40 CFR 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR 60, Appendix A, Method 9 certification course. The observation period shall be a minimum of one (1) hour at initial commissioning and at least one (1) hour thereafter each calendar year during a pig trap flaring operation. In the event no pig trap flaring operations occurred during the calendar year, the permittee shall not be required to complete a Method 22 observation for that year;

2. As the Pigging Flare is of smokeless design, any observation of visible emissions will indicate incorrect operation of the flare. Therefore, upon the observation of visible emissions, the permittee shall, at the next available safe opportunity, cease operation of the flare and attempt to correct the problem. After an attempt to correct the problem, the permittee shall then conduct a minimum of one (1) hour of visible emissions observations according to 13.2.3.a.1. during the next pig trap flaring operation; and

3. The permittee shall maintain records of all monitoring data required by 13.2.3. documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s).

[45CSR13, R13-2896, Condition 16.2.3.]

13.3. Testing Requirements

13.3.1. None

13.4. Recordkeeping Requirements

13.4.1. None

13.5. Reporting Requirements

13.5.1. None

13.6. Compliance Plan

13.6.1. None

14.0 40 CFR 60, Subparts OOOO, OOOOa, and OOOOb Requirements [emission unit ID(s):FUG AREA 1 through 7 and Compressors]

14.1. Limitations and Standards

FUG AREA 1 through 4

14.1.1. In accordance with the request given in Permit Application R13-2896K, the permittee shall operate FUG AREA 1 through 4 in accordance with all applicable requirements given under 40 CFR 60, Subpart OOOOa, even those areas that are eligible to comply with 40 CFR 60, Subparts KKK and OOOO.
[45CSR13, R13-2896, Condition 17.1.1.]

14.1.2. This condition applies to the group of all equipment, except compressors, within a process unit located at an onshore natural gas processing plant.

a. The permittee must comply with the requirements of 40 CFR §§60.482-1a(a), (b), (d), and (e), 60.482-2a, and 60.482-4a through 60.482-10a, except as provided in 40 CFR §60.5401a.

b. The permittee must comply with the provisions of 40 CFR §60.485a except as provided in 40 CFR §60.5400a(f).

c. The permittee must comply with the provisions of 40 CFR §§60.486a and 60.487a except as provided in 40 CFR §§60.5401a, 60.5421a, and 60.5422a.

d. The permittee must use the following provision instead of 40 CFR §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in 40 CFR §60.17) must be used.

[45CSR16; 40 CFR §§60.5400a(a) and (d) to (f)]

FUG AREA 5 through 7

14.1.3. This section applies to process unit equipment affected facilities located at an onshore natural gas processing plant. The permittee must comply with the requirements of 40 CFR §§60.5400b(a) through (l) to reduce methane and VOC emissions from equipment leaks, except as provided in 40 CFR §60.5402b. As an alternative to the standards in this section, the permittee may comply with the requirements in 40 CFR §60.5401b.

a. **General standards.** The permittee must comply with the requirements in paragraphs b. through d. of this condition for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service, and connector in gas/vapor or light liquid service, as applicable. The permittee must comply with the requirements in paragraph e. of this condition for each open-ended valve

or line. The permittee must comply with the requirements in paragraph f. of this condition for each closed vent system and control device used to comply with equipment leak provisions in this condition. The permittee must comply with paragraph g. of this condition for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. The permittee must make repairs as specified in paragraph h. of this condition. The permittee must demonstrate initial compliance with the standards as specified in paragraph i. of this condition. The permittee must demonstrate continuous compliance with the standards as specified in paragraph j. of this condition. The permittee must perform the reporting as specified in paragraph k. of this condition. The permittee must perform the recordkeeping as required in paragraph l. of this condition.

1. The permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in 40 CFR 60, Subpart OOOOb according to the requirements of 40 CFR §60.5399b.

2. Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of Appendix A-6 to 40 CFR 60. Alternatively, if the piece of equipment is in wet gas service, the permittee may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see 40 CFR §60.17).

b. **Monitoring surveys.** The permittee must monitor for leaks using OGI in accordance with Appendix K of 40 CFR 60, unless otherwise specified in paragraphs c. or d. of this condition.

1. Monitoring surveys must be conducted bimonthly.

2. Any emissions observed using OGI are defined as a leak.

c. **Additional requirements for pumps in light liquid service.** In addition to the requirements in paragraph b., the permittee must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal, except as specified in paragraphs c.3. and 4. of this condition. If there are indications of liquids dripping from the pump seal, the permittee must follow the procedure specified in either paragraph c.1. or 2. of this condition.

1. Monitor the pump within 5 calendar days using OGI in accordance with Appendix K or the methods specified in 40 CFR §60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 2,000 ppmv or greater is provided using Method 21 of Appendix A-7 to 40 CFR 60.

2. Designate the visual indications of liquids dripping as a leak and repair the leak as specified in paragraph h. of this condition.

3. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph f. of this condition, it is exempt from the weekly inspection requirements in paragraph c. of this condition.

4. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraph c. of this condition, provided that each pump is visually inspected as often as practicable and at least bimonthly.

d. **Additional requirements for pressure relief devices in gas/vapor service.** In addition to the requirements in paragraph b. of this condition, the permittee must monitor each pressure relief device as specified in paragraph d.1. of this condition, except as specified in paragraph d.2. of this condition.

1. The permittee must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks using the methods specified in 40 CFR §60.5403b. A leak is detected if any emissions are observed using OGI or if an instrument reading of 500 ppmv or greater is provided using Method 21 of Appendix A-7 to 40 CFR 60.

2. Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph f. of this condition is exempt from the requirements of paragraph d.1. of this condition.

e. **Open-ended valves or lines.** Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs e.4. and 5. of this condition. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

1. If evidence of a leak is found at any time by audible, visual, and olfactory (AVO), or any other detection method, a leak is detected.

2. Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

3. 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 shall remain closed at all other times.

4. 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 the requirements of 40 CFR §60.5400b.

5. 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 as specified in paragraphs e. introductory text, e.2., and e.3. are exempt from the requirements of this section.

f. **Closed vent systems and control devices.** Closed vent systems used to comply with the equipment leak provisions of this condition must comply with the requirements in 40 CFR §§60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this condition must comply with the requirements in 40 CFR §§60.5412b, 60.5415b(f), and 60.5417b.

g. **Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.** If evidence of a potential leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph h. of this condition.

h. **Repair requirements.** When a leak is detected, the permittee must comply with the requirements of paragraphs h.1. through 5. of this condition, except as provided in paragraph h.6. of this condition.

1. A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on equipment may be removed after it has been repaired.

2. A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected. A first attempt at repair is not required if the leak is detected using OGI and the equipment identified as leaking would require elevating the repair personnel more than 2 meters above a support surface.

i. First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs h.2.i.a. and b. of this condition, where practicable.

a. Tightening the packing gland nuts.

b. Ensuring that the seal flush is operating at design pressure and temperature.

ii. For each valve where a leak is detected, the permittee must comply with paragraphs h.2.ii.a., b. or c., and d. of this condition.

a. Repack the existing valve with a low-e packing.

b. Replace the existing valve with a low-e valve; or

c. Perform a drill and tap repair with a low-e injectable packing.

d. An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

3. Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraphs h.4., 5., and 6 of this condition.

4. If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, the permittee must make the repair within 5 calendar days of detection.

5. If the repair for AVO or other indication of a leak for open-ended valves or lines; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, the permittee must make the repair within 5 calendar days of detection.

6. Delay of repair of equipment for which leaks have been detected is allowed if repair within 15 days is technically infeasible without a process unit shutdown or as specified in paragraphs h.6.i. through v. of this condition. Repair of this equipment shall 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.

   i. Delay of repair of equipment is allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

   ii. Delay of repair for valves and connectors is allowed if the conditions in paragraphs h.6.ii.a. and b. of this section are met.

      a. The permittee must demonstrate that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

      b. When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph f. of this condition.

   iii. Delay of repair for pumps is allowed if the conditions in paragraphs h.6.iii.a. and b. of this condition are met.

      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.

   iv. If delay of repair is required to repack or replace the valve, the permittee may use delay of repair. Delay of repair beyond a process unit shutdown is 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.

   v. 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 bimonthly monitoring results show no leak remains.

i. **Initial compliance.** The permittee must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5410b(h).

j. **Continuous compliance.** The permittee must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5415b(j).

k. **Reporting.** The permittee must perform the reporting requirements as specified in 40 CFR §§60.5420b(b)(1) and (11) through (13), as applicable, and 40 CFR §60.5422b.

l. **Recordkeeping.** The permittee must perform the recordkeeping requirements as specified in 40 CFR §§60.5420b(c)(8) and (10) through (13), as applicable, and 40 CFR §60.5421b.

[45CSR16; 40 CFR §§60.5400b(a) to (c), (d), (d)(1), (d)(3), and (e) to (l)]

14.1.4. This condition provides alternative standards for process unit equipment affected facilities located at an onshore natural gas processing plant. The permittee may choose to comply with the standards in this condition instead of the requirements in 40 CFR §60.5400b. For purposes of the alternative standards provided in this condition, the permittee must comply with the requirements of paragraphs a. through m. of this condition to reduce methane and VOC emissions from equipment leaks, except as provided in 40 CFR §60.5402b.

a. **General standards.** The permittee must comply with the requirements in paragraph b. of this condition for each pump in light liquid service. The permittee must comply with the requirements of paragraph c. of this condition for each pressure relief device in gas/vapor service. The permittee must comply with the requirements in paragraph d. of this condition for each open-ended valve or line. The permittee must comply with the requirements in paragraph e. of this condition for each closed vent system and control device used to comply with the equipment leak provisions in this condition. The permittee must comply with paragraph f. of this condition for each valve in gas/vapor or light liquid service. The permittee must comply with paragraph g. of this condition for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. The permittee must comply with paragraph h. of this condition for each connector in gas/vapor and light liquid service. The permittee must make repairs as specified in paragraph i. of this condition. The permittee must demonstrate initial compliance with the standards as specified in paragraph j. of this condition. The permittee must demonstrate continuous compliance with the standards as specified in paragraph k. of this condition. The permittee must perform the reporting requirements as specified in paragraph l. of this condition. The permittee must perform the recordkeeping requirements as required in paragraph m. of this condition.

1. The permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in 40 CFR 60, Subpart OOOOb according to the requirements of 40 CFR §60.5399b.

2. Each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the methane and VOC content of a gaseous stream must be below detection limits using Method 18 of Appendix A-6 to 40 CFR 60. Alternatively, if the piece of equipment is in wet gas service, the permittee may choose to determine the methane and VOC content of the stream is below the detection limit of the methods described in ASTM E168-16(R2023), E169-16(R2022), or E260-96 (all incorporated by reference, see 40 CFR §60.17).

b. **Pumps in light liquid service.** The permittee must monitor each pump in light liquid service monthly to detect leaks by the methods specified in 40 CFR §60.5403b, except as provided in paragraphs b.2.

through 6. of this section. A leak is defined as an instrument reading of 2,000 ppmv or greater. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs b.2. through 6. of this condition.

1. In addition to the requirements in paragraph b. of this condition, the permittee must conduct weekly visual inspections of all pumps in light liquid service for indications of liquids dripping from the pump seal. If there are indications of liquids dripping from the pump seal, the permittee must follow the procedure specified in either paragraph b.1.i. or ii. of this condition.

    i. Monitor the pump within 5 days using the methods specified in 40 CFR §60.5403b. A leak is defined as an instrument reading of 2,000 ppmv or greater.

    ii. Designate the visual indications of liquids dripping as a leak, and repair the leak as specified in paragraph i. of this condition.

2. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements in paragraph b. of this condition, provided the requirements specified in paragraphs b.2.i. through v. are met.

    i. Each dual mechanical seal system meets the requirements of paragraph b.2.i.a., b., or c. of this condition.

        a. Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

        b. Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of paragraph e. of this condition; or

        c. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

    ii. The barrier fluid system is in heavy liquid service or does not have the potential to emit methane or VOC.

    iii. Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

    iv. Each pump is checked according to the requirements in paragraph b.1. of this condition.

    v. Each sensor meets the requirements in paragraphs b.2.v.a. through c. of this condition.

        a. Each sensor as described in paragraph b.2.iii. of this condition is checked daily or is equipped with an audible alarm.

        b. The permittee determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

c. If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph b.2.v.b. of this condition, a leak is detected.

3. Any pump that is designated, as described in 40 CFR §60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the requirements of paragraphs b. introductory text, b.1., and b.2. of this condition if the pump:

i. Has no externally actuated shaft penetrating the pump housing;

ii. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background as measured by the methods specified in 40 CFR §60.5403b; and

iii. Is tested for compliance with paragraph b.3.ii. of this condition initially upon designation, annually, and at other times requested by the Administrator.

4. If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process, fuel gas system, or a control device that complies with the requirements of paragraph e. of this condition, it is exempt from paragraphs b., b.1. through 3. of this condition, and the repair requirements of paragraph i. of this condition.

5. Any pump that is designated, as described in 40 CFR §60.5421b(b)(13), as an unsafe-to-monitor pump is exempt from the inspection and monitoring requirements of paragraphs b. introductory text, b.1., and b.2.iv. and v. of this section if the conditions in paragraphs b.5.i. and ii. of this section are met.

i. The permittee demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph b. of this section; and

ii. The permittee has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and the permittee repairs the equipment according to the procedures in paragraph i. of this condition if a leak is detected.

6. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirements in paragraphs b.1. and b.2.iv. of this condition, and the daily requirements of paragraph b.2.v. of this condition, provided that each pump is visually inspected as often as practicable and at least monthly.

c. **Pressure relief devices in gas/vapor service.** The permittee must monitor each pressure relief device quarterly using the methods specified in 40 CFR §60.5403b. A leak is defined as an instrument reading of 500 ppmv or greater above background.

1. In addition to the requirements in paragraph c. introductory text of this condition, after each pressure release, the permittee must monitor each pressure relief device within 5 calendar days after each pressure release to detect leaks. A leak is detected if an instrument reading of 500 ppmv or greater is provided using the methods specified in 40 CFR §60.5403b(b).

2. Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in paragraph e. of this condition is exempt from the requirements of paragraph c. introductory text and c.1. of this condition.

3. Pressure relief devices equipped with a rupture disk are exempt from the requirements of paragraph c.1. of this condition provided the permittee installs a new rupture disk upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in paragraph i.6. of this condition.

d. **Open-ended valves or lines.** Each open-ended valve or line must be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs d.4. and 5. of this condition. The cap, blind flange, plug, or second valve must seal the open end of the valve or line at all times except during operations requiring process fluid flow through the open-ended valve or line.

1. If evidence of a leak is found at any time by AVO, or any other detection method, a leak is detected and must be repaired in accordance with paragraph i. of this condition. A leak is defined as an instrument reading of 500 ppmv or greater if Method 21 of Appendix A-7 to 40 CFR 60 is used.

2. Each open-ended valve or line equipped with a second valve must be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

3. 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 shall remain closed at all other times.

4. 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 the requirements of paragraphs d. introductory text, and d.1. through 3. of this condition.

5. 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 as specified in paragraphs d. introductory text, d.2., and 3. of this condition are exempt from the requirements of this section.

e. **Closed vent systems and control devices.** Closed vent systems used to comply with the equipment leak provisions of this section must comply with the requirements in 40 CFR §§60.5411b and 60.5416b. Control devices used to comply with the equipment leak provisions of this section must comply with the requirements in 40 CFR §§60.5412b, 60.5415b(f), and 60.5417b.

f. **Valves in gas/vapor and light liquid service.** The permittee must monitor each valve in gas/vapor and in light liquid service quarterly to detect leaks by the methods specified in 40 CFR §60.5403b, except as provided in paragraphs f.3. through 5. of this condition.

1. A valve that begins operation in gas/vapor service or in light liquid service after the initial startup date for the process unit must be monitored for the first time within 90 days after the end of its startup period to ensure proper installation, except for a valve that replaces a leaking valve and except as provided in paragraphs f.3. through 5. of this condition.

2. An instrument reading of 500 ppmv or greater is a leak. The permittee must repair each leaking valve according to the requirements in paragraph i. of this condition.

3. Any valve that is designated, as described in 40 CFR §60.5421b(b)(12), for no detectable emissions, as indicated by an instrument reading of less than 500 ppmv above background, is exempt from the monitoring requirements of paragraph f. of this condition if the valve:

   i. Has no externally actuating mechanism in contact with the process fluid;

   ii. Is operated with emissions less than 500 ppmv above background as determined by the methods specified in 40 CFR §60.5403b; and

   iii. Is tested for compliance with paragraph f.3.ii. of this condition initially upon designation, annually, and at other times requested by the Administrator.

4. Any valve that is designated, as described in 40 CFR §60.5421b(b)(13), as an unsafe-to-monitor valve is exempt from the monitoring requirements of paragraph f. of this condition if the requirements in paragraphs f.4.i. and ii. of this condition are met.

   i. The permittee demonstrates that the valve is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph f. of this condition; and

   ii. The permittee has a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and the permittee repairs the equipment according to the procedures in paragraph i. of this condition if a leak is detected.

5. Any valve that is designated, as described in 40 CFR §60.5421b(b)(14), as a difficult-to-monitor valve is exempt from the monitoring requirements of paragraph f. of this condition if the requirements in paragraph f.5.i. through iii. of this condition are met.

   i. The permittee demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

   ii. The process unit within which the valve is located has less than 3.0 percent of its total number of valves designated as difficult-to-monitor.

   iii. The permittee has a written plan that requires monitoring of the at least once per calendar year.

g. **Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.** If evidence of a potential leak is found at any time by AVO, or any other detection method, the permittee must comply with either paragraph g.1. or 2. of this condition.

1. The permittee must monitor the equipment within 5 calendar days by the method specified in 40 CFR §60.5403b and repair any leaks detected according to paragraph i. of this condition. An instrument reading of 10,000 ppmv or greater is defined as a leak.

2. The permittee must designate the AVO, or other indication of a leak as a leak and repair the leak according to paragraph i. of this condition.

h. **Connectors in gas/vapor service and in light liquid service.** The permittee must initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the permittee is required to monitor only those connectors involved in the process change.

1. The permittee must monitor all connectors in gas/vapor service and all connectors in light liquid service annually, except as provided in 40 CFR §60.5399b, paragraph e. of this condition or paragraph h.2. of this condition. If an instrument reading greater than or equal to 500 ppmv is measured, a leak is detected.

2. Any connector that is designated, as described in 40 CFR §60.5421b(b)(13), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs h. introductory text and h.1. of this condition if the requirements of paragraphs h.2.i. and ii. of this condition are met.

i. The permittee demonstrates the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs h. introductory text and h.1. of this condition; and

ii. 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 the permittee repairs the equipment according to the procedures in paragraph i. of this condition if a leak is detected.

3. Inaccessible, ceramic, or ceramic-line connectors.

i. Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs h. and h.1. of this condition, from the leak repair requirements of paragraph i. of this condition, and from the recordkeeping and reporting requirements of 40 CFR §§60.5421b and 60.5422b. An inaccessible connector is one that meets any of the specifications in paragraphs h.3.i.a. through f. of this condition, as applicable.

a. Buried.

b. Insulated in a manner that prevents access to the connector by a monitor probe.

c. Obstructed by equipment or piping that prevents access to the connector by a monitor probe.

d. Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground.

e. Inaccessible because it would require elevating monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold.

f. Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment.

ii. If any inaccessible, ceramic, or ceramic-lined connector is observed by AVO or other means to be leaking, the indications of a leak to the atmosphere by AVO or other means must be eliminated as soon as practicable.

4. Connectors which are part of an instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph h.3. of this condition, are not subject to the recordkeeping requirements of 40 CFR §60.5421b(b)(1).

i. **Repair requirements.** When a leak is detected, comply with the requirements of paragraphs i.1. through 5. of this condition, except as provided in paragraph i.6. of this condition.

1. A weatherproof and readily visible identification tag, marked with the equipment identification number, must be attached to the leaking equipment. The identification tag on the equipment may be removed after it has been repaired.

2. A first attempt at repair must be made as soon as practicable, but no later than 5 calendar days after the leak is detected.

i. First attempts at repair for pumps in light liquid or heavy liquid service include, but are not limited to, the practices described in paragraphs i.2.i.a. and b. of this condition, where practicable.

a. Tightening the packing gland nuts.

b. Ensuring that the seal flush is operating at design pressure and temperature.

ii. For each valve where a leak is detected, the permittee must comply with paragraph i.2.ii.a., b., or c. of this condition, unless the permittee meets the requirements of paragraph i.2.ii.d. of this condition.

a. Repack the existing valve with a low-e packing.

b. Replace the existing valve with a low-e valve; or

c. Perform a drill and tap repair with a low-e injectable packing.

d. An owner or operator is not required to utilize a low-e valve or low-e packing to replace or repack a valve if the owner or operator demonstrates that a low-e valve or low-e packing is not technically feasible. Low-e valve or low-e packing that is not suitable for its intended use is considered to be technically infeasible. Factors that may be considered in

determining technical infeasibility include: retrofit requirements for installation (e.g., re-piping or space limitation), commercial unavailability for valve type, or certain instrumentation assemblies.

3. Repair of leaking equipment must be completed within 15 calendar days after detection of each leak, except as provided in paragraph i.4., 5., or 6. of this condition.

4. If the repair for visual indications of liquids dripping for pumps in light liquid service can be made by eliminating visual indications of liquids dripping, the permittee must make the repair within 5 calendar days of detection.

5. If the repair for AVO or other indication of a leak for open-ended lines or valves; pumps, valves, or connectors in heavy liquid service; or pressure relief devices in light liquid or heavy liquid service can be made by eliminating the AVO, or other indication of a potential leak, the permittee must make the repair within 5 calendar days of detection.

6. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 calendar days is technically infeasible without a process unit shutdown or as specified in paragraphs i.6.i. through v. of this condition. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 calendar days after startup of the process unit.

   i. Delay of repair of equipment will be allowed for equipment which is isolated from the process, and which does not have the potential to emit methane or VOC.

   ii. Delay of repair for valves and connectors will be allowed if the conditions in paragraphs i.6.ii.a. and b. are met.

      a. The permittee demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

      b. When repair procedures are conducted, the purged material is collected and destroyed or recovered in a control device complying with paragraph e. of this condition.

   iii. Delay of repair for pumps will be allowed if the conditions in paragraphs i.6.iii.a. and b. are met.

      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.

   iv. If delay of repair is required to repack or replace the valve, the permittee may use delay of repair. 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.

v. 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 results show no leak remains.

j. **Initial compliance.** The permittee must demonstrate initial compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5410b(h).

k. **Continuous compliance.** The permittee must demonstrate continuous compliance with the standards that apply to equipment leaks at onshore natural gas processing plants as required by 40 CFR §60.5415b(j).

l. **Reporting.** The permittee must perform the reporting requirements as specified in 40 CFR §§60.5420b(b)(1) and (11) through (13), as applicable, and 40 CFR §60.5422b.

m. **Recordkeeping.** The permittee must perform the recordkeeping requirements as specified in 40 CFR §§60.5420b(c)(8) and (10) through (13), as applicable, and 40 CFR §60.5421b.

[45CSR16; 40 CFR §§60.5401b(a) to (c), (c)(1), (c)(4), (c)(5), and (d) to (m)]

Compressors

14.1.5. The permittee shall maintain on-site and available upon request an updated list of all reciprocating compressors and the applicability of each to 40 CFR 60 Subparts OOOO, OOOOa, and OOOOb. For each compressor, the permittee shall comply with all applicable requirements given under 40 CFR 60 Subpart OOOO, OOOOa, or OOOOb, whichever is applicable dependent on the applicability determined under this requirement.
[45CSR13, R13-2896, Condition 17.1.2.; 45CSR§30-5.1.c.]

14.1.6. **Subpart OOOO Standards.** The permittee must comply with the standards in paragraphs a. through d. of this condition for each reciprocating compressor affected facility.

a. The permittee must replace the reciprocating compressor rod packing according to either paragraph a.1. or 2. of this condition or the permittee must comply with paragraph a.3. of this condition.

1. Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of the reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

2. Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

3. Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of 40 CFR §60.5411(a).

b. The permittee must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5410.

c. The permittee must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5415.

d. The permittee must perform the required notification, recordkeeping, and reporting as required by 40 CFR §60.5420.

[45CSR16; 40 CFR §60.5385]

14.1.7. **Closed vent system requirements for reciprocating compressors under Subpart OOOO.**

a. Closed vent system requirements for reciprocating compressors complying with Condition 14.1.6.a.3.

1. The permittee must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the reciprocating compressor rod packing emissions collection system or the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in 40 CFR §§60.5412(a) through (c).

2. The permittee must design and operate the closed vent system with no detectable emissions as demonstrated by 40 CFR §60.5416(b).

3. The permittee must meet the requirements specified in paragraphs a.3.i. and ii. of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

i. Except as provided in paragraph a.3.ii. of this section, the permittee must comply with either paragraph a.3.i.a. or b. of this section for each bypass device.

a. The permittee must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in 40 CFR §60.5416(a)(4) and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. The permittee must maintain records of each time the alarm is activated according to 40 CFR §60.5420(c)(8).

b. The permittee must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

ii. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph a.3.i. of this section.

[45CSR16; 40 CFR §§60.5411 and 60.5411(a)]

14.1.8. **Subpart OOOOa Standards.** The permittee must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs a. through d. of this condition for each reciprocating compressor affected facility.

a. The permittee must replace the reciprocating compressor rod packing according to either paragraph a.1. or 2. of this condition, or the permittee must comply with paragraph a.3. of this condition.

1. On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of the reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

2. Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

3. Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of 40 CFR §§60.5411a(a) and (d).

b. The permittee must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5410a(c).

c. The permittee must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5415a(c).

d. The permittee must perform the reporting as required by 40 CFR §§60.5420a(b)(1) and (4) and the recordkeeping as required by 40 CFR §§60.5420a(c)(3), (6) through (8), and (17), as applicable.

[45CSR16; 40 CFR §60.5385a]

14.1.9. **Closed vent system requirements for reciprocating compressors under Subpart OOOOa.** The permittee must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for the reciprocating compressors complying with Condition 14.1.8.a.3.

a. Closed vent system requirements for reciprocating compressors.

1. The permittee must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system to a process.

2. The permittee must design and operate the closed vent system with no detectable emissions as demonstrated by 40 CFR §60.5416a(b).

3. The permittee must meet the requirements specified in paragraphs a.3.i. and ii. of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

i. Except as provided in paragraph a.3.ii. of this section, the permittee must comply with either paragraph a.3.i.a. or b. of this section for each bypass device.

a. The permittee must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in 40 CFR §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. The permittee must maintain records of each time the alarm is activated according to 40 CFR §60.5420a(c)(8).

b. The permittee must secure the bypass device valve installed at the inlet to the bypass device in a non-diverting position using a car-seal or a lock-and-key type configuration.

ii. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph a.3.i. of this section.

b. Closed vent systems requirements for reciprocating compressors using a control device or routing emissions to a process.

1. The permittee must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected facility are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility, and have it certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs (d)(1)(i) and (ii) of 40 CFR §60.5411a.

i. The permittee must provide the following certification signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of Subpart OOOOa of 40 CFR 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

ii. The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph d.1.i. of this section.

[45CSR16; 40 CFR §§60.5411a, 60.5411a(a), and 60.5411a(d)]

14.1.10. **Subpart OOOOb Standards.** Each reciprocating compressor affected facility must comply with the GHG and VOC standards, using volumetric flow rate as a surrogate, in paragraphs a. through c. of this condition, or the GHG and VOC standards in paragraph d. of this condition. The permittee must also comply with the requirements in paragraphs e. through g. of this condition.

a. The volumetric flow rate of each cylinder, measured in accordance paragraph b. or c. of this condition, must not exceed 2 scfm per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. The permittee must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs a.1. and 2. of this condition and determine the volumetric flow rate per cylinder in accordance with paragraph b. or c. of this condition. If the

volumetric flow rate, measured in accordance with paragraph b. or c. of this condition, for a cylinder exceeds 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), the rod packing or packings must be repaired or replaced as provided in paragraph a.3. of this condition.

1. The permittee must conduct the first volumetric flow rate measurements from the reciprocating compressor rod packing vent on or before 8,760 hours of operation after the last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever date is later.

2. The permittee must conduct subsequent volumetric flow rate measurements from the reciprocating compressor rod packing vent on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the applicable volumetric flow rate of 2 scfm per cylinder (or a combined volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm), or on or before 8,760 hours of operation after last rod packing replacement, whichever date is later.

3. The rod packing must be repaired or replaced within 90 calendar days after the date of the volumetric emissions measurement that exceeded 2 scfm per cylinder. The permittee must conduct follow-up volumetric flow rate measurements from compressor vents using the methods specified in paragraphs b. or c. of this condition within 15 days after the repair (or rod packing replacement) to document that the rate has been reduced to less than 2 scfm per cylinder. Delay of repair will be allowed if the conditions in paragraphs a.3.i. or ii. of this condition are met.

    i. If the repair (or rod packing replacement) is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair (or rod packing replacement) must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per cylinder, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

    ii. If the repair requires replacement of the rod packing or a part, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph a.3.ii.a. of this section, the repair must be completed in accordance with paragraph a.3.ii.b. of this section and documented in accordance with 40 CFR §§60.5420b(c)(5)(viii) through (x).

        a. Rod packing or part supplies had been sufficiently stocked but are depleted at the time of the required repair.

        b. The required rod packing or part replacement must be ordered no later than 10 calendar days after the reciprocating compressor is added to the delay of repair list due to parts unavailability. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement rod packing or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph a.3.i. of this condition.

b. The permittee must determine the volumetric flow rate per cylinder from the reciprocating compressor as specified in paragraph b.1. or 2. of this condition.

1. For reciprocating compressor rod packing equipped with an open-ended vent line on compressors in operating or standby pressurized mode, determine the volumetric flow rate of the rod packing using one of the methods specified in paragraphs b.1.i. through iii. of this condition.

i. Determine the volumetric flow rate at standard conditions from the open-ended vent line using a high-volume sampler according to methods set forth in 40 CFR §60.5386b(c).

ii. Determine the volumetric flow rate at standard conditions from the open-ended vent line using a temporary or permanent meter, according to methods set forth in 40 CFR §60.5386b(b).

iii. Any of the methods set forth in 40 CFR §60.5386b(a) to screen for leaks and emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected according to any of the methods in 40 CFR §60.5386b(a). If emissions are detected using the methods set forth in 40 CFR §60.5386b(a), then the permittee must use one of the methods specified in paragraphs b.1.i. and ii. of this condition to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in 40 CFR §60.5386b(a), then the permittee may assume that the volumetric flow rate is zero.

2. For reciprocating compressor rod packing not equipped with an open-ended vent line on compressors in operating or standby pressurized mode, the permittee must determine the volumetric flow rate of the rod packing using the methods specified in paragraphs b.2.i. and ii. of this condition.

i. The permittee must use the methods described in 40 CFR §60.5386b(a) to conduct leak detection of emissions from the rod packing case into an open distance piece, or, for compressors with a closed distance piece, the permittee must conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

ii. The permittee must measure emissions found in paragraph b.2.i. of this condition using a meter or high-volume sampler according to methods set forth in 40 CFR §60.5386b(b) or (c).

c. For conducting measurements on manifolded groups of reciprocating compressor affected facilities, the permittee must determine the volumetric flow rate from reciprocating compressor rod packing vent as specified in paragraphs c.1. and 2. of this condition.

1. Measure at a single point in the manifold downstream of all compressor vent inputs and, if practical, prior to comingling with other non-compressor emission sources.

2. Determine the volumetric flow rate per cylinder at standard conditions from the common stack using one of the methods specified in paragraphs c.2.i. through iv. of this condition.

i. A temporary or permanent flow meter according to the methods set forth in 40 CFR §60.5386b(b).

ii. A high-volume sampler according to the methods set forth in 40 CFR §60.5386b(c).

iii. An alternative method, as set forth in 40 CFR §60.5386b(d).

iv. Any of the methods set forth in 40 CFR §60.5386b(a) to screen for emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected when using any of the methods in 40 CFR §60.5386b(a). If emissions are detected using the methods set forth in 40 CFR §60.5386b(a), then the permittee must use one of the methods specified in paragraphs c.2.i. through iii. of this condition to determine the volumetric flow rate per cylinder. If emissions are not detected using the methods in 40 CFR §60.5386b(a), then the permittee may assume that the volumetric flow rate is zero.

d. As an alternative to complying with the GHG and VOC standards in paragraphs a. through c. of this condition, owners and operators can meet the requirements specified in paragraph d.1., 2., or 3. of this condition.

1. Collect the methane and VOC emissions from the reciprocating compressor rod packing using a rod packing emissions collection system that is operated to route the rod packing emissions to a process. In order to comply with this option, the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c).

2. Reduce methane and VOC emissions from each rod packing emissions collection system by using a control device that reduces methane and VOC emissions by 95.0 percent. In order to comply with this option, the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b). The cover must be connected through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c) and the closed vent system must be routed to a control device that meets the conditions specified in 40 CFR §60.5412b.

3. As an alternative to conducting the required volumetric flow rate measurements under paragraph a. of this condition, an owner or operator can choose to comply by replacing the rod packing on or before 8,760 hours of operation after startup, on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever date is later.

e. The permittee must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5410b(e).

f. The permittee must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by 40 CFR §60.5415b(g).

g. The permittee must perform the reporting requirements as specified in 40 CFR §§60.5420b(b)(1), (6), and (11) through (13), as applicable; and the recordkeeping requirements as specified in 40 CFR §§60.5420b(c)(5) and (8) through (13), as applicable.

[45CSR16; 40 CFR §60.5385b]

14.1.11. **Closed vent system requirements for reciprocating compressors and process unit equipment under Subpart OOOOb.** For each cover or closed vent system at the reciprocating compressor and process unit equipment affected facilities, the permittee must comply with the applicable requirements of paragraphs a. through c. of this condition.

a. *Closed vent system requirements.*

1. **Reciprocating compressor rod packing.** The permittee must design the closed vent system to capture and route all gases, vapors, and fumes to a process.

2. **Process Unit Equipment.** The permittee must design the closed vent system to capture and route all gases, vapors, and fumes to a process or a control device that meets the requirements specified in 40 CFR §§60.5412b(a) through (d).

3. The permittee must design and operate the closed vent system with no identifiable emissions as demonstrated by 40 CFR §§60.5416b(a) and (b).

4. **Bypass devices.** The permittee must meet the requirements specified in paragraphs a.4.i. and ii. of this condition if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or being routed to a process.

i. Except as provided in paragraph a.4.ii. of this condition, the permittee must comply with either paragraph a.4.i.a. or b. of this condition for each bypass device.

a. The permittee must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device. The flow indicator must be capable of taking periodic readings as specified in 40 CFR §60.5416b(a)(4)(i) and sound an alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process, and sent to the atmosphere. The permittee must maintain records of each time the alarm is activated according to 40 CFR §60.5420b(c)(10).

b. The permittee must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

ii. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of 40 CFR §60.5411b(a)(4)(i).

b. *Cover requirements for reciprocating compressors.*

1. The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the reciprocating compressor rod packing emissions collection system.

2. Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

i. To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

ii. To inspect or sample the material in the unit;

iii. To inspect, maintain, repair, or replace equipment located inside the unit; or

iv. To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph a. of this condition to a control device or to a process.

3. The permittee must design and operate the cover with no identifiable emissions as demonstrated by 40 CFR §§60.5416b(a) and (b), except when operated as provided in paragraphs b.2.i. through iv. of this condition.

c. *Design requirements.*

1. The permittee must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all gases, vapors, and fumes from the affected facility are routed to the control device or process and that the control device or process is of sufficient design and capacity to accommodate all emissions from the affected facility. The assessment must be certified by a qualified professional engineer or an in-house engineer with expertise on the design and operation of the closed vent system in accordance with paragraphs c.1.i. and ii. of this condition.

i. The permittee must provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of 40 CFR 60, Subpart OOOOb. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

ii. The assessment shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in paragraph c.1.i. of this condition.

[45CSR16; 40 CFR §§60.5411b(a), (b)(1), (b)(2), (b)(4), and (c)]

14.1.12. The permittee is deemed to be in compliance with 40 CFR 60 Subpart OOOO if they are in compliance with all applicable provisions of 40 CFR 60, Subpart OOOOa.
[45CSR16; 40 CFR §60.5370(d)]

14.1.13. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall 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 Administrator which may include but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR §60.8(c) do not apply to 40 CFR Subpart OOOOa or Subpart OOOOb.
[45CSR16; 40 CFR §60.5370(b); 40 CFR §60.5370a(b); 40 CFR §60.5370b(b)]

14.2. Monitoring Requirements

FUG AREAS 1 through 4 (40 CFR 60, Subpart OOOOa)

14.2.1. Exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants:

a. The permittee may comply with the following exceptions to the provisions of 40 CFR §§60.5400a(a) and (b).

b. 1. Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in 40 CFR §60.485a(b) except as provided in 40 CFR §60.5400a(c) and in 40 CFR §60.5401a(b)(4), and 40 CFR §§60.482-4a(a) through (c) of 40 CFR 60, Subpart VVa.

2. If an instrument reading of 500 ppm or greater is measured, a leak is detected.

3. Leak Repair:

i. When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in 40 CFR §60.482-9a.

ii. A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

c. Sampling connection systems are exempt from the requirements of 40 CFR §60.482-5a.

d. An owner or operator may use the following provisions instead of 40 CFR §60.485a(e):

1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in 40 CFR §60.17).

2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in 40 CFR §60.17).

e. An owner or operator may use the following provisions instead of 40 CFR §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of Appendix A-7 of 40 CFR 60, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in 40 CFR §60.486a(e)(8). For each scale, divide the arithmetic difference of the most recent calibration and the post-test calibration response by the corresponding calibration gas value, and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the most recent calibration response, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the most recent calibration response, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[45CSR16; 40 CFR §§60.5401a(a), (b)(1) to (3), (c), (f), and (g)]

FUG AREA 5 through 7 (40 CFR 60, Subpart OOOOb)

14.2.2. Exceptions to the GHG and VOC standards for process unit equipment affected facilities:

a. The permittee may comply with the following exceptions to the provisions of 40 CFR §§60.5400b(a) and 60.5401b(a), as applicable.

b. The permittee may use the following provisions instead of 40 CFR §60.5403b(d):

1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM D86-96 (incorporated by reference, see 40 CFR §60.17).

2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM D86-96 (incorporated by reference, see 40 CFR §60.17).

c. Equipment that is in vacuum service, except connectors in gas/vapor and light liquid service, is excluded from the requirements of 40 CFR §§60.5400b(b) through (g), if it is identified as required in 40 CFR §60.5421b(b)(15). Equipment that is in vacuum service is excluded from the requirements of 40 CFR §§60.5401b(b) through (g) if it is identified as required in 40 CFR §60.5421b(b)(15).

d. Equipment that is designated as having the potential to emit methane or VOC less than 300 hr/yr is excluded from the requirements of 40 CFR §§60.5400b(b) through (g) and 40 CFR §§60.5401b(b) through (h), if it is identified as required in 40 CFR §60.5421b(b)(16) and it meets any of the conditions specified in paragraphs d.1. through 3. of this condition.

1. The equipment has the potential to emit methane or VOC only during startup and shutdown.

2. The equipment has the potential to emit methane or VOC only during process malfunctions or other emergencies.

3. The equipment is backup equipment that has the potential to emit methane or VOC only when the primary equipment is out of service.

[45CSR16; 40 CFR §§60.5402b(a) and (d) to (f)]

14.2.3. **Initial compliance demonstration for process unit equipment affected facilities under 40 CFR 60, Subpart OOOOb.** To achieve initial compliance with the GHG and VOC standards for process unit equipment affected facilities as required by 40 CFR §60.5400b, the permittee must comply with paragraphs a. through d. and k. through o. of this condition, unless the permittee meets and complies with the exception in 40 CFR §§60.5402b(b), (e), or (f) or meets the exemption in 40 CFR §60.5402b(c). If the permittee complies with the GHG and VOC standards for process unit equipment affected facilities using the alternative standards in 40 CFR §60.5401b, the permittee must comply with paragraphs e. through o. of this condition, unless the permittee meets the exemption in 40 CFR §60.5402b(b) or (c) or the exception in 40 CFR §60.5402b(e) or (f).

a. The permittee must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor or light liquid service and connector in gas/vapor or light liquid service as required by 40 CFR §60.5400b(b).

b. The permittee must conduct monitoring as required by 40 CFR §60.5400b(c) for each pump in light liquid service.

c. The permittee must conduct monitoring as required by 40 CFR §60.5400b(d) for each pressure relief device in gas/vapor service.

d. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5400b(e).

e. The permittee must conduct monitoring for each pump in light liquid service as required by 40 CFR §60.5401b(b).

f. The permittee must conduct monitoring for each pressure relief device in gas/vapor service as required by 40 CFR §60.5401b(c).

g. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5401b(d).

h. The permittee must conduct monitoring for each valve in gas/vapor or light liquid service as required by 40 CFR §60.5401b(f).

i. The permittee must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by 40 CFR §60.5401b(g).

j. The permittee must conduct monitoring for each connector in gas/vapor or light liquid service as required by 40 CFR §60.5401b(h).

k. For each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or a control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or a control device, the permittee must meet the requirements of paragraph k.1. through 6. of this condition.

    1. Reduce methane and VOC emissions by 95.0 percent or greater and as demonstrated by the requirements of 40 CFR §60.5413b or route to a process.

    2. Install a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c) to capture all emissions from each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir, each pump which captures and transports leakage from the seal or seals, or each pressure relief device which captures and transports leakage through the pressure relief device and route all emissions to a process or to a control device that meets the conditions specified in 40 CFR §60.5412b.

    3. If routing to a control device, conduct an initial performance test as required in 40 CFR §60.5413b within 180 days after initial startup, or install a control device tested under 40 CFR §60.5413b(d)

which meets the criteria in 40 CFR §§60.5413b(d)(11) and (e), and the permittee must comply with the continuous compliance requirements of 40 CFR §60.5415b(f).

4. Conduct the initial inspections of the closed vent system and bypasses, if applicable, as required in 40 CFR §§60.5416b(a) and (b).

5. Install and operate the continuous parameter monitoring systems in accordance with 40 CFR §§60.5417b(a) through (i), as applicable.

6. Maintain the records as required by 40 CFR §§60.5420b(c)(8) and (c)(10) through (13), as applicable and submit the reports as required by 40 CFR §§60.5420b(b)(11) through (13), as applicable.

l. The permittee must tag and repair each identified leak as required in 40 CFR §60.5400b(h) or §60.5401b(i), as applicable.

m. The permittee must submit the notice required by 40 CFR §60.5420b(a)(1).

n. The permittee must submit the initial semiannual report and subsequent semiannual report as required by 40 CFR §60.5422b.

o. The permittee must maintain the records specified by 40 CFR §60.5421b.

[45CSR16; 40 CFR §60.5410b(h)]

14.2.4. **Continuous compliance demonstration for process unit equipment affected facilities under 40 CFR 60, Subpart OOOOb.** For each process unit equipment affected facility, the permittee must demonstrate continuous compliance with the requirements of 40 CFR §60.5400b according to paragraphs a. through d. and k. through o. of this condition, unless the permittee meets and complies with the exception in 40 CFR §60.5402b(b), (e), or (f) or meets the exemption in 40 CFR §60.5402b(c). Alternatively, if the permittee complies with the GHG and VOC standards for process unit affected facilities using the standards in 40 CFR §60.5401b, the permittee must comply with paragraphs e. through o. of this condition, unless the permittee meets the exemption in 40 CFR §60.5402b(b) or (c) or the exception in 40 CFR §§60.5402b(e) and (f).

a. The permittee must conduct monitoring for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas/vapor and light liquid service and connector in gas/vapor and light liquid service as required by 40 CFR §60.5400b(b).

b. The permittee must conduct monitoring as required by 40 CFR §60.5400b(c) for each pump in light liquid service.

c. The permittee must conduct monitoring as required by 40 CFR §60.5400b(d) for each pressure relief device in gas/vapor service.

d. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5400b(e).

e. The permittee must conduct monitoring for each pump in light liquid service as required by 40 CFR §60.5401b(b).

f. The permittee must conduct monitoring for each pressure relief device in gas/vapor service as required by 40 CFR §60.5401b(c).

g. The permittee must comply with the equipment requirements for each open-ended valve or line as required by 40 CFR §60.5401b(d).

h. The permittee must conduct monitoring for each valve in gas/vapor or light liquid service as required by 40 CFR §60.5401b(f).

i. The permittee must conduct monitoring for each pump, valve, and connector in heavy liquid service and each pressure relief device in light liquid or heavy liquid service as required by 40 CFR §60.5401b(g).

j. The permittee must conduct monitoring for each connector in gas/vapor or light liquid service as required by 40 CFR §60.5401b(h).

k. The permittee must collect emissions and meet the closed vent system requirements as required by 40 CFR §60.5416b for each pump equipped with a dual mechanical seal system that degasses the barrier fluid reservoir to a process or a control device, each pump which captures and transports leakage from the seal or seals to a process or control device, or each pressure relief device which captures and transports leakage through the pressure relief device to a process or control device.

l. The permittee must comply with the requirements specified in 40 CFR §60.5415b(f).

m. The permittee must tag and repair each identified leak as required in 40 CFR §60.5400(h) or §60.5401b(i), as applicable.

n. The permittee must submit semiannual reports as required by 40 CFR §60.5422b and the annual reports in 40 CFR §§60.5420b(b)(11)(i) through (iv), as applicable.

o. The permittee must maintain the records specified by 40 CFR §§60.5420b(c)(8), (c)(10), and (c)(12) as applicable and 40 CFR §60.5421b.

[45CSR16; 40 CFR §60.5415b(j)]

Compressors

14.2.5. **Initial compliance demonstration for 40 CFR 60, Subpart OOOO.** To achieve initial compliance with the standards for each reciprocating compressor affected facility the permittee must comply with paragraphs a. through d. of this condition.

a. If complying with 40 CFR §60.5385(a)(1) or (2), during the initial compliance period, the permittee must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

b. If complying with 40 CFR §60.5385(a)(3), the permittee must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of 40 CFR §60.5411(a).

c. The permittee must submit the initial annual report for the reciprocating compressor as required in 40 CFR §60.5420(b).

d. The permittee must maintain the records as specified in 40 CFR §60.5420(c)(3) for each reciprocating compressor affected facility.

[45CSR16; 40 CFR §60.5410(c)]

14.2.6. **Continuous compliance demonstration for 40 CFR 60, Subpart OOOO.** For each reciprocating compressor affected facility complying with 40 CFR §60.5385(a)(1) or (2), the permittee must demonstrate continuous compliance according to paragraphs a. through c. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385(a)(3), the permittee must demonstrate continuous compliance according to paragraph d. of this condition.

a. The permittee must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

b. The permittee must submit the annual report as required in 40 CFR §60.5420(b) and maintain records as required in 40 CFR §60.5420(c)(3).

c. The permittee must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

d. The permittee must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in 40 CFR §§60.5416(a) and (b).

[45CSR16; 40 CFR §60.5415(c)]

14.2.7. **Initial compliance demonstration for 40 CFR 60, Subpart OOOOa.** To achieve initial compliance with the standards for each reciprocating compressor affected facility the permittee must comply with paragraphs a. through d. of this condition.

a. If complying with 40 CFR §60.5385a(a)(1) or (2), during the initial compliance period, the permittee must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

b. If complying with 40 CFR §60.5385a(a)(3), the permittee must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of 40 CFR §§60.5411a(a) and (d).

c. The permittee must submit the initial annual report for the reciprocating compressor as required in 40 CFR §§60.5420a(b)(1) and (4).

d. The permittee must maintain the records as specified in 40 CFR §60.5420a(c)(3) for each reciprocating compressor affected facility.

[45CSR16; 40 CFR §60.5410a(c)]

14.2.8. **Continuous compliance demonstration for 40 CFR 60, Subpart OOOOa.** For each reciprocating compressor affected facility complying with 40 CFR §60.5385a(a)(1) or (2), the permittee must demonstrate continuous compliance according to paragraphs a. through c. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385a(a)(3), the permittee must demonstrate continuous compliance according to paragraph c.4. of this condition.

a. The permittee must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

b. The permittee must submit the annual reports as required in 40 CFR §§60.5420a(b)(1) and (4) and maintain records as required in 40 CFR §60.5420a(c)(3).

c. The permittee must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

d. The permittee must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in 40 CFR §§60.5416a(a) and (b).

[45CSR16; 40 CFR §60.5415a(c)]

14.2.9. **Initial compliance demonstration for 40 CFR 60, Subpart OOOOb.** To demonstrate initial compliance with the GHG and VOC standards for each reciprocating compressor affected facility as required by 40 CFR §60.5385b, the permittee must comply with paragraphs a. through g. of this condition.

a. If the permittee complies with 40 CFR §60.5385b by maintaining volumetric flow rate at or below 2 scfm per cylinder (or a combined cylinder volumetric flow rate greater than the number of compression cylinders multiplied by 2 scfm) as required by 40 CFR §60.5385b(a), the permittee must maintain volumetric flow rate at or below 2 scfm and the permittee must conduct the initial annual volumetric flow rate measurement as required by 40 CFR §60.5385b(a)(1).

b. If the permittee complies with 40 CFR §60.5385b by collecting the methane and VOC emissions from the reciprocating compressor rod packing using a rod packing emissions collection system as required by 40 CFR §60.5385b(d)(1), the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b), route emissions to a process through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c), and the permittee must conduct the initial inspections required in 40 CFR §§60.5416b(a) and (b).

c. If the permittee complies with 40 CFR §60.5385b(d) by collecting the emissions from the rod packing emissions collection system by using a control device to reduce VOC and methane emissions by 95.0 percent as required by 40 CFR §60.5385b(d)(2), the permittee must equip the reciprocating compressor with a cover that meets the requirements of 40 CFR §60.5411b(b), route emissions to a control device that meets the conditions specified in 40 CFR §60.5412b through a closed vent system that meets the requirements of 40 CFR §§60.5411b(a) and (c) and the permittee must conduct the initial inspections required in 40 CFR §§60.5416b(a) and (b).

d. If the permittee complies with 40 CFR §60.5385b(d)(2), the permittee must conduct an initial performance test as required in 40 CFR §60.5413b within 180 days after initial startup, or install a control

device tested under 40 CFR §60.5413b(d) which meets the criteria in 40 CFR §§60.5413b(d)(11) and (e) and the permittee must comply with the continuous compliance requirements of 40 CFR §60.5415b(f).

e. If the permittee complies with 40 CFR §60.5385b(d)(2), the permittee must install and operate the continuous parameter monitoring systems in accordance with 40 CFR §§60.5417b(a) through (i), as applicable.

f. The permittee must submit the initial annual report for the reciprocating compressor as required in 40 CFR §§60.5420b(b)(1), (6), and (11) through (13), as applicable.

g. The permittee must maintain the records as specified in 40 CFR §§60.5420b(c)(5) and (8) through (13) as applicable.

[45CSR16; 40 CFR §60.5410b(e)]

14.2.10. **Continuous compliance demonstration for 40 CFR 60, Subpart OOOOb.** For each reciprocating compressor affected facility complying with 40 CFR §§60.5385b(a) through (c), the permittee must demonstrate continuous compliance according to paragraphs a., e., and f. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385b(d)(1) or (2), the permittee must demonstrate continuous compliance according to paragraphs b., e., and f. of this condition. For each reciprocating compressor affected facility complying with 40 CFR §60.5385b(d)(3), the permittee must demonstrate continuous compliance according to paragraphs c. through f. of this condition.

a. The permittee must maintain the volumetric flow rate at or below 2 scfm per cylinder (or at or below the combined volumetric flow rate determined by multiplying the number of cylinders by 2 scfm), and the permittee must conduct the required volumetric flow rate measurement of the reciprocating compressor rod packing vents in accordance with 40 CFR §60.5385b(b) on or before 8,760 hours of operation after the last volumetric flow rate measurement which demonstrated compliance with the applicable volumetric flow rate.

b. The permittee must operate the rod packing emissions collection system to route emissions to a control device or to a process through a closed vent system and continuously comply with the cover and closed vent requirements of 40 CFR §60.5416b. If the permittee complies with 40 CFR §60.5385b(d) by use a control device, the permittee also must comply with the requirements in 40 CFR §60.5415b(f).

c. The permittee must continuously monitor the number of hours of operation for each reciprocating compressor affected facility since initial startup, since the previous flow rate measurement, or since the date of the most recent reciprocating compressor rod packing replacement, whichever date is latest.

d. The permittee must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 8,760 hours.

e. The permittee must submit the annual reports as required in 40 CFR §§60.5420b(b)(1), (6), and (11)(i) through (iv), as applicable.

f. The permittee must maintain records as required in 40 CFR §§60.5420b(c)(5), (8) through (10), and (12), as applicable.

[45CSR16; 40 CFR §60.5415b(g)]

14.2.11. **Additional continuous compliance requirements for reciprocating compressor and process unit equipment affected facilities under 40 CFR 60, Subpart OOOOb.** For each reciprocating compressor affected facility and each process unit equipment affected facility referenced to 40 CFR §60.5415b(f) from either 40 CFR §60.5415b(g)(2) or (j)(12), the permittee must also install monitoring systems as specified in 40 CFR §60.5417b, demonstrate continuous compliance according to 40 CFR §60.5415b(f)(1), maintain the records in 40 CFR §60.5415b(f)(2), and comply with the reporting requirements specified in 40 CFR §60.5415b(f)(3).
[45CSR16; 40 CFR §60.5415b(f)]

14.2.12. **Continuous monitoring requirements for control devices under Subpart OOOOb.** The permittee must meet the requirements of 40 CFR §60.5417b to demonstrate continuous compliance for each control device used to meet emission standards for reciprocating compressor and process unit equipment affected facilities.
[45CSR16; 40 CFR §60.5417b]

14.3. Testing Requirements

14.3.1. **Inspections for closed vent systems and covers installed on each reciprocating compressor affected facility under Subpart OOOO.** Except as provided in 40 CFR §§60.5416(b)(11) and (12), the permittee must inspect each closed vent system according to the procedures and schedule specified in paragraphs a. and b. of this condition, inspect each cover according to the procedures and schedule specified in paragraph c. of this condition, and inspect each bypass device according to the procedures of paragraph d. of this condition for reciprocating compressors complying with permit condition 14.1.6.a.3.

a. For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the permittee must meet the requirements specified in paragraphs a.1. and 2. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416(b) to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in 40 CFR §60.5416(b) to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

b. For closed vent system components other than those specified in paragraph a. of this condition, the permittee must meet the requirements of paragraphs b.1. through 3. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416(b) to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

2. Conduct annual inspections according to the test methods and procedures specified in 40 CFR §60.5416(b) to demonstrate that the components or connections operate with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

3. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(6).

c. For each cover, the permittee must meet the following requirements:

1. Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, the permittee must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

2. The permittee must initially conduct the inspections specified in paragraph c.1. of this condition following the installation of the cover. Thereafter, the permittee must perform the inspection at least once every calendar year, except as provided in 40 CFR §§60.5416(b)(11) and (12). The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420(c)(7).

d. For each bypass device, except as provided for in 40 CFR §60.5411, the permittee must meet the following requirements:

1. Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

2. If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. The permittee must maintain records of the inspections according to 40 CFR §60.5420(c)(8).

[45CSR16; 40 CFR §60.5416(a)]

14.3.2. **No detectable emissions test methods and procedures under Subpart OOOO.** If the permittee is required to conduct an inspection of a closed vent system or cover at the reciprocating compressor affected facility as specified in 40 CFR §60.5416(a)(1), (2), or (3), the permittee must meet the requirements of 40 CFR §§60.5416(b)(1) through (13).
[45CSR16; 40 CFR §60.5416(b)]

14.3.3. **Inspections for closed vent systems and covers installed on each reciprocating compressor affected facility under Subpart OOOOa.** Except as provided in paragraphs (b)(11) and (12) of 40 CFR §60.5416a, the permittee must inspect each closed vent system according to the procedures and schedule specified in paragraphs a. and b. of this condition, inspect each cover according to the procedures and schedule specified in paragraph c. of this condition, and inspect each bypass device according to the procedures of paragraph d. of this condition for reciprocating compressors complying with condition 14.1.8.a.3.

a. For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the permittee must meet the requirements specified in paragraphs a.1. and 2. of this section.

1. Conduct an initial inspection according to the test methods and procedures specified in condition 14.3.4. to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in condition 14.3.4. to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

b. For closed vent system components other than those specified in paragraph a. of this section, the permittee must meet the requirements of paragraphs b.1. through 3. of this section.

1. Conduct an initial inspection according to the test methods and procedures specified in condition 14.3.4. to demonstrate that the closed vent system operates with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

2. Conduct annual inspections according to the test methods and procedures specified in condition 14.3.4. to demonstrate that the components or connections operate with no detectable emissions. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

3. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(6).

c. For each cover, the permittee must meet the requirements in paragraphs c.1. and 2. of this condition.

1. Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, the permittee must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

2. The permittee must initially conduct the inspections specified in paragraph c.1. of this condition following the installation of the cover. Thereafter, the permittee must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of 40 CFR §60.5416a. The permittee must maintain records of the inspection results as specified in 40 CFR §60.5420a(c)(7).

d. For each bypass device, except as provided for in 40 CFR §60.5411a(a)(3)(ii), the permittee must meet the requirements of paragraph d.1. or 2. of this section.

1. Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

2. If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. The permittee must maintain records of the inspections according to 40 CFR §60.5420a(c)(8).

[45CSR16; 40 CFR §60.5416a(a)]

14.3.4. **No detectable emissions test methods and procedures under Subpart OOOOa.** If the permittee is required to conduct an inspection of a closed vent system or cover at the reciprocating compressor affected facility as specified in paragraph (a)(1), (2), or (3) of 40 CFR §60.5416a, the permittee must meet the requirements of paragraphs (b)(1) through (13) of 40 CFR §60.5416a.
[45CSR16; 40 CFR §60.5416a(b)]

14.3.5. **Test methods and procedures for reciprocating compressor affected facilities under Subpart OOOOb.**

a. The permittee must use one of the methods described in paragraphs a.1. or 2. of this condition to screen for emissions or leaks from the reciprocating compressor rod packing when complying with 40 CFR §60.5385b(b)(1)(iii).

1. **OGI instrument.** Use an OGI instrument for equipment leak detection as specified in paragraph a.1.i. of this condition. For the purposes of paragraph a.1.i. of this condition, any visible emissions observed by the OGI instrument from reciprocating rod packing is a leak.

i. **OGI instrument as specified in Appendix K of 40 CFR 60.** For reciprocating compressor affected facilities located at onshore natural gas processing plants, use an OGI instrument to screen for emissions from reciprocating rod packing in accordance with the protocol specified in Appendix K of 40 CFR 60.

2. **Method 21.** Use Method 21 in Appendix A-7 to 40 CFR 60 according to 40 CFR §60.5403b(b)(1) and (2). For the purposes of this condition, an instrument reading of 500 parts per million by volume (ppmv) above background or greater is a leak.

b. The permittee must determine natural gas volumetric flow rate using a rate meter which meets the requirement in Method 2D in Appendix A-1 of 40 CFR 60. Rate meters must be calibrated on an annual basis according to the requirements in Method 2D.

c. The permittee must use a high-volume sampler to measure emissions of the reciprocating compressor rod packing, in accordance with 40 CFR §§60.5386b(c)(1) through (7).

d. As an alternative to a high-volume sampler, the permittee may use any other method that has been validated in accordance with the procedures specified in Method 301 in Appendix A in 40 CFR 63, subject to Administrator approval, as specified in 40 CFR §60.8(b).

[45CSR16; 40 CFR §§60.5386b(a), (a)(1), (a)(1)(i), (a)(2), and (b) to (d)]

14.3.6. **Performance testing procedures for control devices used to demonstrate compliance with the emission standards for reciprocating compressor and process unit equipment affected facilities.** The permittee must demonstrate that a control device achieves the performance requirements of 40 CFR §60.5412b(a)(1) or (2) using the performance methods and procedures specified in 40 CFR §60.5413b.
[45CSR16; 40 CFR §60.5413b]

14.3.7. **Inspections for closed vent systems, covers, and bypass devices at reciprocating compressor and process unit equipment affected facilities under Subpart OOOOb.** If the permittee installs a control device or routes emissions to a process, the permittee must inspect each closed vent system according to the procedures and schedule specified in paragraphs a. and b. of this condition, inspect each cover according to the procedures and schedule specified in paragraph c. of this condition, and inspect each bypass device according to the procedures of paragraph d. of this condition, except as provided in 40 CFR §§60.5416b(b)(7) and (8).

a. For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the permittee must meet the requirements specified in paragraphs a.1. through 3. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416b(b) to demonstrate that the closed vent system operates with no identifiable emissions within the first 30 calendar days after startup of the affected facility routing emissions through the closed vent system.

2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in 40 CFR §60.5416b(b) to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

3. Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in 40 CFR §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with inspections required by paragraph a.2. of this condition.

b. For closed vent system components other than those specified in paragraph a.1. of this condition, the permittee must meet the requirements of paragraphs b.1. through 4. of this condition.

1. Conduct an initial inspection according to the test methods and procedures specified in 40 CFR §60.5416b(b) within the first 30 calendar days after startup of the affected facility routing emissions

through the closed vent system to demonstrate that the closed vent system operates with no identifiable emissions.

2. Conduct inspections according to the test methods, procedures, and frequencies specified in 40 CFR §60.5416b(b) to demonstrate that the components or connections operate with no identifiable emissions.

3. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. The permittee must monitor a component or connection using the test methods and procedures in 40 CFR §60.5416b(b) to demonstrate that it operates with no identifiable emissions following any time the component is repaired or replaced or the connection is unsealed.

4. Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site, as specified in 40 CFR §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph b.3. of this condition.

c. For each cover, the permittee must meet the requirements of paragraphs c.1. through 4. of this condition.

1. Conduct the inspections specified in c.2. through 4. of this condition to identify defects that could result in air emissions and to ensure the cover operates with no identifiable emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, the permittee must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

2. An initial inspection according to the test methods and procedures specified in 40 CFR §60.5416b(b), following installation of the cover to demonstrate that each cover operates with no identifiable emissions.

3. Conduct AVO inspections in accordance with and at the same frequency as specified for fugitive emissions components affected facilities located at the same type of site as specified in 40 CFR §60.5397b(g). Process unit equipment affected facilities must conduct annual AVO inspections concurrent with the inspections required by paragraph a.2. of this condition.

4. Inspections according to the test methods, procedures, and schedules specified in 40 CFR §60.5416b(b) to demonstrate that each cover operates with no identifiable emissions.

d. For each bypass device, except as provided for in 40 CFR §60.5411b(a)(4)(ii), the permittee must meet the requirements of paragraphs d.1. or 2. of this condition.

1. Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device and to the atmosphere.

2. If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device.

[45CSR16; 40 CFR §60.5416b(a)]

14.3.8. **No identifiable emissions test methods and procedures under Subpart OOOOb.** If the permittee is required to conduct an inspection of a closed vent system and cover as specified in 40 CFR §60.5416b(a)(1), (2), or (3) or 40 CFR §60.5398b(b), the permittee must meet the requirements of 40 CFR §§60.5416b(b)(1) through (9).
[45CSR16; 40 CFR §60.5416b(b)]

14.4. Recordkeeping Requirements

FUG AREAS 1 through 4 (40 CFR 60, Subpart OOOOa)

14.4.1. The permittee must comply with the requirements of condition 14.4.2. in addition to the requirements of 40 CFR §60.486a.
[45CSR16; 40 CFR §60.5421a(a)]

14.4.2. The following recordkeeping requirements apply to pressure relief devices subject to the requirements of 40 CFR §60.5401a(b)(1).

a. When each leak is detected as specified in 40 CFR §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

b. When each leak is detected as specified in 40 CFR §60.5401a(b)(2), the information specified in paragraphs b.1. through 10. of this condition must be recorded in a log and shall be kept for 2 years in a readily accessible location:

1. The instrument and operator identification numbers and the equipment identification number.

2. The date the leak was detected and the dates of each attempt to repair the leak.

3. Repair methods applied in each attempt to repair the leak.

4. “Above 500 ppm” if the maximum instrument reading measured by the methods specified in 40 CFR §60.5400a(d) after each repair attempt is 500 ppm or greater.

5. “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

6. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

7. The expected date of successful repair of the leak if a leak is not repaired within 15 days.

8. Dates of process unit shutdowns that occur while the equipment is unrepaired.

9. The date of successful repair of the leak.

10. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR §60.482-4a(a). The designation of equipment subject to the provisions of 40 CFR §60.482-4a(a) must be signed by the owner or operator.

[45CSR16; 40 CFR §60.5421a(b)]

FUG AREAS 5 through 7 (40 CFR 60, Subpart OOOOb)

14.4.3. **Recordkeeping requirements for process unit equipment affected facilities under Subpart OOOOb.** The permittee must maintain a record of each equipment leak monitoring inspection and each leak identified under 40 CFR §60.5400b and §60.5401b as specified in paragraphs b.1. through 17. of this condition. The record must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

a. The permittee may comply with the recordkeeping requirements for multiple process unit equipment affected facilities in one recordkeeping system if the system identifies each record by each facility.

b. The permittee must maintain the monitoring inspection records specified in paragraphs b.1. through 17. of this section.

1. Equipment Identification. Note that connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of 40 CFR 60, Subpart OOOOb are identified as a group, and the number of connectors subject is indicated.

2. Date and start and end times of the monitoring inspection.

3. Inspector name.

4. Leak determination method used for the monitoring inspection (i.e., OGI, Method 21, or AVO).

5. Monitoring instrument identification (OGI and Method 21 only).

6. Type of equipment monitored.

7. Process unit identification.

8. The records specified in Section 12 of Appendix K of 40 CFR 60, for each monitoring inspection conducted with OGI.

9. The records in paragraph b.9.i. through vii., for each monitoring inspection conducted with Method 21 of Appendix A-7 to 40 CFR 60.

i. Instrument reading.

ii. Date and time of instrument calibration and initials of operator performing the calibration.

iii. Calibration gas cylinder identification, certification date, and certified concentration.

iv. Instrument scale used.

v. A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of Appendix A-7 to 40 CFR 60.

vi. Results of the daily calibration drift assessment.

vii. If the permittee makes the calibration gas, a description of the procedure used.

10. For visual inspections of pumps in light liquid service, keep the records specified in paragraphs b.10.i. through iii., for each monitored equipment:

i. Date of inspection.

ii. Inspector name.

iii. Result of inspection (i.e., visual indications of liquids dripping from the pump seal or no visual indications of liquids dripping from the pump seal).

11. For each leak detected, the records specified in paragraphs b.11.i. through v. of this condition:

i. The instrument and operator identification numbers and the process unit and equipment identification numbers. For leaks identified via AVO methods, enter the specific sensory method for instrument identification number.

ii. The date the leak was detected.

iii. For each attempt to repair the leak, record:

a. The date.

b. The repair method applied.

c. Indication of whether a leak was still detected following each attempt to repair the leak.

iv. The date of successful repair of the leak and the method of monitoring used to confirm the repair, as specified in paragraph b.11.iv.a. through c. of this condition.

a. If Method 21 of Appendix A-7 to 40 CFR 60 is used to confirm the repair, maintain a record of the maximum instrument reading measured by Method 21 of Appendix A-7 to 40 CFR 60.

b. If OGI conducted in accordance with Appendix K of 40 CFR 60 is used to confirm the repair, maintain a record of video footage of the repair confirmation.

c. If the leak is repaired by eliminating AVO indications of a leak, maintain a record of the specific sensory method used to confirm that the evidence of the leak is eliminated.

v. For each repair delayed beyond 15 calendar days after detection of the leak, record:

a. "Repair delayed" and the reason for the delay.

b. The signature of the certifying official who made the decision that repair could not be completed without a process shutdown.

c. The expected date of successful repair of the leak.

d. Dates of process unit shutdowns that occur while the equipment is unrepaired.

12. A list of identification numbers for equipment that are designated for no detectable emissions complying with the provisions of 40 CFR §60.5401b.

13. A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

14. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

15. A list of identification numbers for equipment that is in vacuum service.

16. A list of identification numbers for equipment designated as having the potential to emit methane or VOC less than 300 hr/yr.

17. A list of identification numbers for valves where it was infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was infeasible.

[45CSR16; 40 CFR §60.5421b]

Compressors

14.4.4. **Recordkeeping requirements under Subpart OOOO.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in paragraphs a. through e. of this condition. All records required by 40 CFR 60, Subpart OOOO must be maintained either onsite or at the nearest local field office for at least 5 years.

a. For each reciprocating compressor affected facility, the permittee must maintain the following records:

1. Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

2. Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in 40 CFR §60.5385(a)(3).

3. Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in 40 CFR §60.5385.

b. Records of each closed vent system inspection required under 40 CFR §§60.5416(a)(1) and (2) for reciprocating compressors.

c. A record of each cover inspection required under 40 CFR §60.5416(a)(3) for reciprocating compressors.

d. If the permittee is subject to the bypass requirements of 40 CFR §60.5416(a)(4) for reciprocating compressors, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

e. If the permittee is subject to the closed vent system no detectable emissions requirements of 40 CFR §60.5416(b) for reciprocating compressors, a record of the monitoring conducted in accordance with 40 CFR §60.5416(b).

[45CSR16; 40 CFR §§60.5420(c), (c)(3), (c)(6), (c)(7), (c)(8), and (c)(9)]

14.4.5. **Recordkeeping requirements under Subpart OOOOa.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in paragraphs a. through e. of this condition. All records required by 40 CFR 60, Subpart OOOOa must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60, Subpart OOOOa that are submitted electronically via the EPA's CDX may be maintained in electronic format.

a. For each reciprocating compressor affected facility, the permittee must maintain the records in paragraphs a.1. through 3. of this condition.

1. Records of the cumulative number of hours of operation or number of months since initial startup or since the previous replacement of the reciprocating compressor rod packing, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

2. Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in 40 CFR §60.5385a(a)(3).

3. Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in 40 CFR §60.5385a, including the date and time the deviation began, duration of the deviation, and a description of the deviation.

b. Records of each closed vent system inspection required under 40 CFR §§60.5416a(a)(1) and (2) and (b) for reciprocating compressors as required in paragraphs b.1. through 3. of this condition.

1. A record of each closed vent system inspection or no detectable emissions monitoring survey. The permittee must include an identification number for each closed vent system (or other unique identification description selected) and the date of the inspection.

2. For each defect or leak detected during inspections required by 40 CFR §§60.5416a(a)(1) and (2), (b), (c)(1), or (d), the permittee must record the location of the defect or leak, a description of the defect or the maximum concentration reading obtained if using Method 21 of Appendix A-7 of 40 CFR 60, the date of detection, and the date the repair to correct the defect or leak is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416a(b)(10), the permittee must record the reason for the delay and the date the repair is expected to be completed.

c. A record of each cover inspection required under 40 CFR §60.5416a(a)(3) for reciprocating compressors as required in paragraphs c.1. through 3. of this condition.

1. A record of each cover inspection. The permittee must include an identification number for each cover (or other unique identification description selected) and the date of the inspection.

2. For each defect detected during inspections required by 40 CFR §60.5416a(a)(3), the permittee must record the location of the defect, a description of the defect, the date of detection, the corrective action taken to repair the defect, and the date the repair to correct the defect is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416a(b)(10), the permittee must record the reason for the delay and the date the repair is expected to be completed.

d. If the permittee is subject to the bypass requirements of 40 CFR §60.5416a(a)(4) for reciprocating compressors, the permittee must prepare and maintain a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

e. For each closed vent system routing to a control device or process, the records of the assessment conducted according to 40 CFR §60.5411a(d):

1. A copy of the assessment conducted according to 40 CFR §60.5411a(d)(1);

2. A copy of the certification according to 40 CFR §60.5411a(d)(1)(i); and

3. The owner or operator shall retain copies of all certifications, assessments, and any related records for a period of five years and make them available if directed by the delegated authority.

[45CSR16; 40 CFR §§60.5420a(c)(3), (c)(6), (c)(7), (c)(8), and (c)(17)]

14.4.6. **Recordkeeping requirements under Subpart OOOOb.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in 40 CFR §§60.5420b(c)(1) through (15). All records required by 40 CFR 60, Subpart OOOOb must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60, Subpart OOOOb that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain

electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

For each reciprocating compressor affected facility, the permittee must maintain the records in paragraphs a. through j. of this condition and in condition 14.4.7., as applicable. If complying with an alternative GHG and VOC standard under 40 CFR §60.5398b, in lieu of the information specified in condition 14.4.7.a., the permittee must provide the information specified in 40 CFR §60.5424b.

a. For each reciprocating compressor affected facility, the permittee must maintain records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in 40 CFR §60.5385b, including a description of each deviation, the date and time each deviation began and the duration of each deviation in hours.

b. Records of the date of installation of a rod packing emissions collection system and closed vent system as specified in 40 CFR §60.5385b(d).

c. Records of the cumulative number of hours of operation since initial startup or since the previous volumetric flow rate measurement, as applicable. Alternatively, a record that emissions from the rod packing are being routed to a process through a closed vent system.

d. A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

e. Records for all flow meters, composition analyzers and pressure gauges used to measure volumetric flow rates as specified in paragraphs e.1. through 6. of this condition.

    1. Description of standard method published by a consensus-based standards organization or industry standard practice.

    2. Records of volumetric flow rate calculations conducted according to 40 CFR §60.5385b(b) or (c), as applicable.

    3. Records of manufacturer operating procedures and measurement methods.

    4. Records of manufacturer's recommended procedures or an appropriate industry consensus standard method for calibration and results of calibration, recalibration, and accuracy checks.

    5. Records which demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions. The permittee must include the date of the demonstration, the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations. If adjustments were made to the mathematical relationships, a record and description of such adjustments.

    6. Record of each initial calibration or a recalibration which failed to meet the required accuracy specification and the date of the successful recalibration.

f. Date when performance-based volumetric flow rate is exceeded.

g. The date of successful replacement or repair of reciprocating compressor rod packing, including follow-up performance-based volumetric flow rate measurement to confirm successful repair.

h. Identification of each reciprocating compressor placed on delay of repair because of rod packing or part unavailability and explanation for each delay of repair.

i. For each reciprocating compressor that is placed on delay of repair because of replacement rod packing or part unavailability, the operator must document: the date the rod packing or part was added to the delay of repair list, the date the replacement rod packing or part was ordered, the anticipated rod packing or part delivery date (including any estimated shipment or delivery date provided by the vendor), and the actual arrival date of the rod packing or part.

j. Date of planned shutdowns that occur while there are any reciprocating compressors that have been placed on delay of repair due to the unavailability of rod packing or parts to conduct repairs.

[45CSR16; 40 CFR §§60.5420b(c) and (c)(5)]

14.4.7. **Additional recordkeeping requirements for reciprocating compressor and process unit equipment affected facilities under Subpart OOOOb.** The permittee must maintain the records identified as specified in 40 CFR §60.7(f) and in 40 CFR §§60.5420b(c)(1) through (15). All records required by 40 CFR 60, Subpart OOOOb must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by 40 CFR 60, Subpart OOOOb that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

a. Records of each closed vent system inspection required under 40 CFR §§60.5416b(a)(1), (a)(2), and (b) for reciprocating compressor and process unit equipment affected facilities as required in paragraphs a.1. through 4. of this condition.

1. A record of each closed vent system inspection or no identifiable emissions monitoring survey. The permittee must include an identification number for each closed vent system (or other unique identification description selected by the permittee), the date of the inspection, and the method used to conduct the inspection (i.e., visual, AVO, OGI, Method 21 of Appendix A-7 to 40 CFR 60).

2. For each defect or emissions detected during inspections required by 40 CFR §§60.5416b(a)(1) and (2) or (b), the permittee must record the location of the defect or emissions; a description of the defect; the maximum concentration reading obtained if using Method 21 of Appendix A-7 to 40 CFR 60; the indication of emissions detected by AVO if using AVO; the date of detection; the date of each attempt to repair the emissions or defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect or emissions is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416b(b)(6), the permittee must record the reason for the delay and the date the repair is expected to be completed.

4. Parts of the closed vent system designated as unsafe to inspect as described in 40 CFR §60.5416b(b)(7) or difficult to inspect as described in 40 CFR §60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the closed vent system.

b. A record of each cover inspection required under 40 CFR §60.5416b(a)(3) for the reciprocating compressor as required in paragraphs b.1. through 4. of this condition.

1. A record of each cover inspection. The permittee must include an identification number for each cover (or other unique identification description selected), the date of the inspection, and the method used to conduct the inspection (i.e., AVO, OGI, Method 21 of Appendix A-7 to 40 CFR 60).

2. For each defect detected during the inspection, the permittee must record the location of the defect; a description of the defect, the date of detection, the maximum concentration reading obtained if using Method 21 of Appendix A-7 to 40 CFR 60; the indication of emissions detected by AVO if using AVO; the date of each attempt to repair the defect; the corrective action taken during each attempt to repair the defect; and the date the repair to correct the defect is completed.

3. If repair of the defect is delayed as described in 40 CFR §60.5416b(b)(6), the permittee must record the reason for the delay and the date the repair is expected to be completed.

4. Parts of the cover designated as unsafe to inspect as described in 40 CFR §60.5416b(b)(7) or difficult to inspect as described in 40 CFR §60.5416b(b)(8), the reason for the designation, and written plan for inspection of that part of the cover.

c. For each bypass subject to the bypass requirements of 40 CFR §60.5416b(a)(4), the permittee must maintain a record of the following, as applicable: readings from the flow indicator; each inspection of the seal or closure mechanism; the date and time of each instance the key is checked out; date and time of each instance the alarm is sounded.

d. Records for each control device used to comply with the emission reduction standard in 40 CFR §60.5385b(d)(2) for reciprocating compressor affected facilities or 40 CFR §§60.5400b(f) or 60.5401b(e) for the process equipment affected facilities, as required in 40 CFR §§60.5420b(c)(11)(i) through (viii). If using an enclosed combustion device or flare using an alternative test method approved under 40 CFR §60.5412b(d), keep records of the information in 40 CFR §60.5420b(c)(11)(ix), in lieu of the records required by 40 CFR §§60.5412b(c)(11)(i) through (iv) and (vi) through (viii).

e. For each closed vent system routing to a control device or process, the records of the assessment conducted according to 40 CFR §60.5411b(c):

1. A copy of the assessment conducted according to 40 CFR §60.5411b(c)(1); and

2. A copy of the certification according to 40 CFR §§60.5411b(c)(1)(i) and (ii).

f. A copy of each performance test submitted under 40 CFR §60.5420b(b)(12) or (b)(13).

[45CSR16; 40 CFR §§60.5420b(c) and (c)(8) to (c)(13)]

14.5. Reporting Requirements

FUG AREAS 1 through 4 (40 CFR 60, Subpart OOOOa)

14.5.1. The permittee must comply with the requirements of conditions 14.5.2. and 14.5.3. in addition to the requirements of 40 CFR §§60.487a(a), (b)(1) through (3), and (c)(2)(i) through (iv). The permittee must

submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for 40 CFR 60, Subpart OOOOa or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI website (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to 40 CFR 60, Subpart OOOOa is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available in CEDRI for at least 90 days, the permittee must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in 40 CFR 60, Subpart OOOOa, regardless of the method in which the report is submitted.
[45CSR16; 40 CFR §60.5422a(a)]

14.5.2. An owner or operator must include the following information in the initial semiannual report in addition to the information required in 40 CFR §§60.487a(b)(1) through (3): Number of pressure relief devices subject to the requirements of 40 CFR §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of 40 CFR §60.482-4a(a) and those pressure relief devices complying with 40 CFR §60.482-4a(c).
[45CSR16; 40 CFR §60.5422a(b)]

14.5.3. An owner or operator must include the information specified in paragraphs a. and b. of this condition in all semiannual reports in addition to the information required in 40 CFR §§60.487a(c)(2)(i) through (iv):

a. Number of pressure relief devices for which leaks were detected as required in 40 CFR §60.5401a(b)(2); and

b. Number of pressure relief devices for which leaks were not repaired as required in 40 CFR §60.5401a(b)(3).

[45CSR16; 40 CFR §60.5422a(c)]

FUG AREAS 5 through 7 (40 CFR 60, Subpart OOOOb)

14.5.4. a. **Notification requirements.** The permittee must submit notifications according to paragraph a.1. of this condition for the process unit equipment affected facilities specified in 40 CFR §60.5365b that were constructed, modified, or reconstructed during the reporting period.

1. For a process unit equipment affected facility located at an onshore natural gas processing plant, the permittee must submit the notifications required in 40 CFR §§60.7(a)(1), (3), and (4) and 40 CFR §60.15(d).

[40 CFR §§60.5420b(a) and (a)(1)]

b. **Reporting requirements.** The permittee must submit annual reports containing the information specified in 40 CFR §§60.5420b(b)(1) through (b)(14) following the procedure specified in 40 CFR §60.5420b(b)(15). The permittee must submit performance test reports as specified in 40 CFR §60.5420b(b)(12) or (13), if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. The permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in 40 CFR §§60.5420b(b)(1) through (14). Annual reports may coincide with Title

V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

1. The general information specified in paragraphs b.1.i. through iv. of this condition is required for all reports.

   i. The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

   ii. An identification of each affected facility being included in the annual report.

   iii. Beginning and ending dates of the reporting period.

   iv. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

   [40 CFR §§60.5420b(b)(1) and (b)(1)(i) to (iv)]

2. For each process unit equipment affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, the permittee must submit the information in paragraphs b.2.i. through v. of this condition. For each process unit equipment which uses a closed vent system to route to a process, the permittee must submit the information in paragraphs b.2.i. through iv. of this condition.

   i. Dates of each inspection required under 40 CFR §§60.5416b(a) and (b).

   ii. Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

   iii. Date and time of each bypass alarm or each instance the key is checked out if the permittee is subject to the bypass requirements of 40 CFR §60.5416b(a)(4).

   iv. The permittee must submit the certification signed by the qualified professional engineer or in-house engineer according to 40 CFR §60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

v. If the permittee complies with the emissions standard for the process unit equipment affected facility with a control device, the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (L), unless an enclosed combustion device or flare is used an alternative test method approved under 40 CFR §60.5412b(d). If an enclosed combustion device or flare using an alternative test method approved under 40 CFR §60.5412b(d), the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (C) and (L) through (P).

[40 CFR §60.5420b(b)(11)]

3. Within 60 days after the date of completing each performance test (see 40 CFR §60.8) required by 40 CFR 60, Subpart OOOOb, except testing conducted by the manufacturer as specified in 40 CFR §60.5413b(d), the permittee must submit the results of the performance test following the procedures specified in 40 CFR §60.5420b(d). Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.
[40 CFR §60.5420b(b)(12)]

4. For combustion control devices tested by the manufacturer in accordance with 40 CFR §60.5413b(d), an electronic copy of the performance test results required by 40 CFR §60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*.
[40 CFR §60.5420b(b)(13)]

5. The permittee must submit the annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 40 CFR 60, Subpart OOOOb and following the procedure specified in 40 CFR §60.5420b(d). If the reporting form specific to 40 CFR 60, Subpart OOOOb is not available on the CEDRI website at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in 40 CFR 60, Subpart OOOOb, regardless of the method in which the report is submitted.
[40 CFR §60.5420b(b)(15)]

[45CSR16; 40 CFR §60.5420b(b)]

c. **Electronic reporting.** If the permittee is required to submit notifications or reports following the procedure specified in this paragraph, the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information you claim as CBI.
[45CSR16; 40 CFR §60.5420b(d)]

d. **Additional reporting requirements for process unit equipment affected facilities.**

1. The permittee must submit semiannual reports using the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart OOOOb and following the procedure specified in paragraph c. of this condition. If the reporting form specific to 40 CFR 60, Subpart OOOOb is not available on the CEDRI website at the time that the report is due, submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted within 45 days after the end of the semiannual reporting period, regardless of the method in which the report is submitted.

2. The initial semiannual report must include the following information:

i. The general information specified in paragraph d.3.i. of this condition.

ii. For each process unit:

a. Process unit identification.

b. Number of valves subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(f).

c. Number of pumps subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(b).

d. Number of connectors subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(h).

e. Number of pressure relief devices subject to the monitoring requirements of 40 CFR §§60.5400b(b) and 60.5401b(c).

f. The information in 40 CFR §§60.5420b(c)(3) and (4).

3. All subsequent semiannual reports must include the following information:

i. The general information specified in paragraphs d.3.i.a. through c. of this condition.

a. The company name, facility site name, and address of the affected facility.

b. Beginning and ending dates of the reporting period.

c. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

ii. Process unit identification for each process unit.

iii. For each month during the semiannual reporting period for each process unit report:

a. Number of valves for which leaks were detected as described in 40 CFR §60.5400b(b) or §60.5401b(f).

b. Number of valves for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i), the number of instances where it was technically infeasible to replace leaking valves with low-e valves or repack existing valves with low-e packing technology, including the reasoning for why it was technically infeasible.

c. Number of pumps for which leaks were detected as described 40 CFR §60.5400b(b) or §60.5401b(b).

d. Number of pumps for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

e. Number of connectors for which leaks were detected as described in 40 CFR §60.5400b(b) or §60.5401b(h).

f. Number of connectors for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

g. Number of pressure relief devices for which leaks were detected as described in 40 CFR §60.5400b(b) or §60.5401b(c).

h. Number of pressure relief devices for which leaks were not repaired as required in 40 CFR §60.5400b(h) or § 60.5401b(i).

i. Number of open-ended valves or lines for which leaks were detected as described in 40 CFR §60.5400b(e) or §60.5401b(d).

j. Number of open-ended valves or lines for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

k. Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were detected as described in 40 CFR §60.5400b(g) or §60.5401b(g).

l. Number of pumps, valves, or connectors in heavy liquid service or pressure relief device in light liquid or heavy liquid service for which leaks were not repaired as required in 40 CFR §60.5400b(h) or §60.5401b(i).

m. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

iv. Dates of process unit shutdowns which occurred within the semiannual reporting period.

v. Revisions to items reported according to paragraph d.2. of this condition if changes have occurred since the initial report or subsequent revisions to the initial report.

[45CSR16; 40 CFR §60.5422b]

Compressors

14.5.5. **Reporting requirements under Subpart OOOO.** The permittee must submit annual reports containing the information specified in paragraphs a. and b. of this condition to the Administrator and performance test reports as specified in paragraph (b)(7) of 40 CFR §60.5420. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs a. and b. of this condition. Annual reports may coincide with Title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

a. The general information specified in paragraphs a.1. through 4. of this condition.

1. The company name and address of the affected facility.

2. An identification of each affected facility being included in the annual report.

3. Beginning and ending dates of the reporting period.

4. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

b. For each reciprocating compressor affected facility, the information specified in paragraphs b.1. and 2. of this condition.

1. The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

2. Records of deviations specified in paragraph (c)(3)(iii) of 40 CFR §60.5420 that occurred during the reporting period.

[45CSR16; 40 CFR §§60.5420(b), (b)(1), and (b)(4)]

14.5.6. **Reporting requirements under Subpart OOOOa.** The permittee must submit annual reports containing the information specified in paragraphs (b)(1), (b)(4), and (b)(12) of 40 CFR §60.5420a. The permittee must submit annual reports following the procedure specified in paragraph (b)(11) of 40 CFR §60.5420a. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If the permittee owns or operates more than one affected facility, the permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) and (12) of 40 CFR §60.5420a. Annual reports may coincide with Title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

a. The general information specified in paragraphs a.1. through 4. of this condition is required for all reports.

1. The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

2. An identification of each affected facility being included in the annual report.

3. Beginning and ending dates of the reporting period.

4. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

b. For each reciprocating compressor affected facility, the information specified in paragraphs b.1. through 3. of this condition.

1. The cumulative number of hours of operation or the number of months since initial startup or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

2. If applicable, for each deviation that occurred during the reporting period and recorded as specified in paragraph (c)(3)(iii) of 40 CFR §60.5420a, the date and time the deviation began, duration of the deviation, and a description of the deviation.

3. If required to comply with 40 CFR §60.5385a(a)(3), the information in paragraphs b.3.i. through iii. of this condition.

i. Dates of each inspection required under 40 CFR §§60.5416a(a) and (b);

ii. Each defect or leak identified during each inspection, and date of repair or date of anticipated repair if repair is delayed; and

iii. Date and time of each bypass alarm or each instance the key is checked out if subject to the bypass requirements of 40 CFR §60.5416a(a)(4).

c. The permittee must submit reports to the EPA via CEDRI, except as outlined in 40 CFR §60.5420a(b)(11). CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The permittee must use the appropriate electronic report template on the CEDRI website for 40 CFR 60, Subpart OOOOa (*https://www.epa.gov/electronic-reporting-air-emissions/cedri/*). If the reporting form specific to 40 CFR 60, Subpart OOOOa is not available on the CEDRI website at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available in CEDRI for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the reports must be submitted by the deadlines specified in 40 CFR 60, Subpart OOOOa, regardless of the method in which the reports are submitted. The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information claimed as CBI. Although we do not expect persons to assert a claim of CBI, if the permittee wishes to assert a CBI claim for some of the information in the report, submit a complete file using the appropriate electronic report template on the CEDRI website, including information claimed to be CBI, to the EPA following the procedures in 40 CFR §§60.5420a(b)(11)(i) and (ii). Clearly mark the part or all of the information claimed to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. Submit the same file submitted to the CBI office with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in 40 CFR §60.5420a(b)(11).

1. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov* and, as described above, should include clear CBI markings. Files should be flagged to the attention of the Oil and Natural Gas Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if the permittee does not have a file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

2. If the permittee cannot transmit the file electronically, the permittee may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Oil and Natural Gas Sector Lead, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

d. The permittee must submit the certification signed by the qualified professional engineer or in-house engineer according to 40 CFR §60.5411a(d) for each closed vent system routing to a control device or process.

[45CSR16; 40 CFR §§60.5420a(b), (b)(1), (b)(4), (b)(11), and (b)(12)]

14.5.7. a. **Notification requirements under Subpart OOOOb.** The permittee must submit notifications according to paragraph a.1. of this condition for reciprocating compressor affected facilities specified in 40 CFR §60.5365b that were constructed, modified, or reconstructed during the reporting period.

1. For a reciprocating compressor affected facility, the permittee is not required to submit the notifications required in 40 CFR §§60.7(a)(1), (3), and (4) and 40 CFR §60.15(d).

[40 CFR §§60.5420b(a) and (a)(1)]

b. **Reporting requirements under Subpart OOOOb.** The permittee must submit annual reports containing the information specified in 40 CFR §§60.5420b(b)(1), (b)(6), and (b)(11) through (b)(13) following the procedure specified in 40 CFR §60.5420b(b)(15). The permittee must submit performance test reports as specified in 40 CFR §60.5420b(b)(12) or (13), if applicable. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to 40 CFR §60.5410b. Subsequent annual reports are due no later than the same date each year as the initial annual report. The permittee may submit one report for multiple affected facilities provided the report contains all of the information required as specified in 40 CFR §§60.5420b(b)(1) through (14). Annual reports may coincide with Title V reports as long as all the required elements of the annual report are included. The permittee may arrange with the Administrator a common schedule on which reports required by 40 CFR 60 may be submitted as long as the schedule does not extend the reporting period.

1. The general information specified in paragraphs b.1.i. through iv. of this condition is required for all reports.

i. The company name, facility site name associated with the affected facility, U.S. Well ID or U.S. Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

ii. An identification of each affected facility being included in the annual report.

iii. Beginning and ending dates of the reporting period.

iv. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. If the report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph.

[40 CFR §§60.5420b(b)(1) and (b)(1)(i) to (iv)]

2. For each reciprocating compressor affected facility, the information specified in paragraphs b.2.i. through vii. of this condition, as applicable.

   i. The cumulative number of hours of operation since initial startup, since the previous volumetric flow rate measurement, or since the previous reciprocating compressor rod packing replacement, as applicable, which have elapsed prior to conducting the volumetric flow rate measurement or emissions screening. Alternatively, a statement that emissions from the rod packing are being routed to a process or control device through a closed vent system.

   ii. If applicable, for each deviation that occurred during the reporting period and recorded as specified in 40 CFR §60.5420b(c)(5)(i), the date and time the deviation began, duration of the deviation in hours and a description of the deviation. If no deviations occurred during the reporting period, the permittee must include a statement that no deviations occurred during the reporting period.

   iii. A description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable.

   iv. If complying with 40 CFR §60.5385b(d)(1) or (2), the information in paragraphs b.3.i. through iv. of this condition. If complying by routing emissions to a control device, as required in 40 CFR §60.5385b(d)(2), the information in paragraph b.3.v. of this condition.

   v. Number and type of rod packing replacements/repairs on delay of repair and explanation for each delay of repair.

   vi. Date of planned shutdown(s) that occurred during the reporting period if there are any rod packing replacements/repairs that have been placed on delay of repair.

   vii. If complying with an alternative GHG and VOC standard under 40 CFR §60.5398b, in lieu of the information specified in paragraphs b.3.i. and ii. of this condition, the permittee must provide the information specified in 40 CFR §60.5424b.

   [40 CFR §60.5420b(b)(6)]

3. For each reciprocating compressor affected facility which uses a closed vent system routed to a control device to meet the emissions reduction standard, the permittee must submit the information in paragraphs b.3.i. through v. of this condition. For each reciprocating compressor which uses a closed vent system to route to a process, the permittee must submit the information in paragraphs b.3.i. through iv. of this condition. For each reciprocating compressor equipped with a cover, the permittee must submit the information in paragraphs b.3.i. and ii. of this condition.

   i. Dates of each inspection required under 40 CFR §§60.5416b(a) and (b).

   ii. Each defect or emissions identified during each inspection and the date of repair or the date of anticipated repair if the repair is delayed.

   iii. Date and time of each bypass alarm or each instance the key is checked out if the permittee is subject to the bypass requirements of 40 CFR §60.5416b(a)(4).

iv. The permittee must submit the certification signed by the qualified professional engineer or in-house engineer according to 40 CFR §60.5411b(c) for each closed vent system routing to a control device or process in the reporting year in which the certification is signed.

v. If the permittee complies with the emissions standard for the reciprocating compressor affected facility with a control device, the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (L), unless an enclosed combustion device or flare is used an alternative test method approved under 40 CFR §60.5412b(d). If the permittee uses an enclosed combustion device or flare using an alternative test method approved under 40 CFR §60.5412b(d), the information in 40 CFR §§60.5420b(b)(11)(v)(A) through (C) and (L) through (P).

[40 CFR §60.5420b(b)(11)]

4. Within 60 days after the date of completing each performance test (see 40 CFR §60.8) required by 40 CFR 60, Subpart OOOOb, except testing conducted by the manufacturer as specified in 40 CFR §60.5413b(d), the permittee must submit the results of the performance test following the procedures specified in 40 CFR §60.5420b(d). Data collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.
[40 CFR §60.5420b(b)(12)]

5. For combustion control devices tested by the manufacturer in accordance with 40 CFR §60.5413b(d), an electronic copy of the performance test results required by 40 CFR §60.5413b(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following website: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*.
[40 CFR §60.5420b(b)(13)]

6. The permittee must submit the annual report using the appropriate electronic report template on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 40 CFR 60, Subpart OOOOb and following the procedure specified in 40 CFR §60.5420b(d). If the reporting form specific to 40 CFR 60, Subpart OOOOb is not available on the CEDRI website at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, the permittee must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.
[40 CFR §60.5420b(b)(15)]

[45CSR16; 40 CFR §60.5420b(b)]

c. **Electronic reporting.** If the permittee is required to submit notifications or reports following the procedure specified in this paragraph, the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information you claim as CBI.
[45CSR16; 40 CFR §60.5420b(d)]

14.6. Compliance Plan

14.6.1. None

15.0 NPP: Turbines and Duct Burners [emission point ID(s): TB1A/B to TB4A/B]

15.1. Limitations and Standards

15.1.1. **Combustion Turbines**
The combustion turbines (CTs) shall meet the following requirements:

a. R13-3493 only authorizes construction and operation of one (1) set of the four (4) same make/model CTs defined as either "Scenario A" or "Scenario B" under the table titled "Natrium Power Plant" in Section 1.1. of this permit. This permit does not authorize any scenario where more than four (4) CTs are authorized.

b. Each group of authorized CTs shall be the make, model, and size as specified under the "Natrium Power Plant" table and shall only be fired by pipeline-quality natural gas, ethane, or some combination thereof.

c. With the exception of operation during times defined as "startup" or "shutdown" pursuant to 15.2.1., at all times each CT is in operation, each unit shall be controlled by Selective Catalytic Reduction (SCR) for control of NO_X emissions and an Oxidation Catalyst for control of CO and unburnt hydrocarbon (UHC) emissions.

d. Each CT shall be fired using good combustion practices. Good Combustion Practices shall mean activities such as maintaining operating logs and recordkeeping, conducting training, ensuring maintenance knowledge, performing routine and preventive maintenance, conducting burner and control adjustments, monitoring fuel quality, etc.

e. The maximum emissions from each CT shall not exceed the limits (during the specific operational times) as given in the following table:

Table 15.1.1.e. – Scenario A: CT Emission Limits

GE LM6000PG SPRINT Emission Limits				
Pollutant	**lb/hr**			**ton/year**
	Startup	**Shutdown**	**Steady-State**	
CO	152.90	95.82	2.04	10.40
NO_X	41.86	41.86	3.35	15.13
$PM_{2.5}$/PM_{10}/PM[(1)]	3.19	3.19	3.86	16.91
SO_2	1.64	1.64	1.64	7.19
VOC	4.81	4.81	0.44	1.97
Formaldehyde	0.34	0.34	0.34	1.50
Total HAPs	0.49	0.49	0.49	2.17

(1) Includes condensables.

Table 15.1.1.e. – Scenario B: CT Emission Limits

Siemens SGT-800 Emission Limits				
Pollutant	**lb/hr**			**ton/year**
	Startup	**Shutdown**	**Steady-State**	
CO	51.84	12.48	0.61	10.74
NO_X	25.68	20.88	3.49	20.35
$PM_{2.5}$/PM_{10}/PM(1)	0.72	0.48	3.52	14.86
SO_2	1.69	1.69	1.69	7.39
VOC	2.88	0.48	0.35	1.86
Formaldehyde	0.13	0.13	0.13	0.57
Total HAPs	0.29	0.29	0.29	1.25

(1) Includes condensables.

f. The CTs shall each not operate in the modes defined as "startup" and "shutdown" (as defined under 15.2.1.) in excess of the annual hourly limits given in the following table:

Table 15.1.1.f.: CT Annual Startup/Shutdown Hours of Operation Limits

CT	Startup	Shutdown
GE LM6000PG SPRINT	12	12
Siemens SGT-800	256	256

g. At the time operation of the CTs commences, the permittee shall have, and make available to the Director upon request, guarantees from the appropriate equipment vendors that the following maximum emission rates are achievable from the equipment in question:

Table 15.1.1.g.: CT Vendor Guarantee Requirements (in ppmvd at 15% O_2)

Pollutant	GE LM6000PG SPRINT		Siemens SGT-800	
	Uncontrolled	**Controlled**	**Uncontrolled**	**Controlled**
CO	94.0	2.0	5.0	0.5
NO_X	25.0	2.0	35.0	1.8
$PM_{2.5}$/PM_{10}/PM	N/A	N/A	2.5	N/A
VOC	11.0	1.0	5.0	0.5
Formaldehyde	N/A	N/A	0.1	0.1

h. The amount of power supplied by each CT to the utility distribution systems (not used at the plant and supplied instead to the "grid") shall be less than 219,000 MW-hour per year.

[45CSR13, R13-3493, 4.1.2.a. to h.]

15.1.2. **Duct Burners**

The Duct Burners, identified as TB1A/B through TB4A/B, shall meet the following requirements:

a. Each Duct Burner will not exceed an MDHI of 475.1 MMBtu/hr and shall only be fired by pipeline-quality natural gas, ethane, or some combination thereof.

b. At all times each Duct Burner is in operation, the exhaust from each unit shall be controlled by Selective Catalytic Reduction (SCR) for control of NO_X emissions and an oxidation catalyst for control of CO and unburnt hydrocarbon (UHC) emissions. The Duct Burners shall not be operated during times defined as "startup" or "shutdown" pursuant to condition 15.2.1.

c. Each Duct Burner shall be fired using good combustion practices. Good combustion practices shall mean activities such as maintaining operating logs and recordkeeping, conducting training, ensuring maintenance knowledge, performing routine and preventative maintenance, conducting burner and control adjustments, monitoring fuel quality, etc.

d. The maximum emissions from each Duct Burner shall not exceed the limits as given in the following table.

Table 15.1.2.d.: Per-Duct Burner Emission Limits

Pollutant	lb/hour	ton/year
CO	2.12	1.86
NO_X	3.50	3.05
$PM_{2.5}$/PM_{10}/PM[(1),(2)]	3.65	3.19
SO_2[(3)]	0.28	0.24
VOC	0.13	0.11
Formaldehyde	0.03	0.03
Total HAPs	0.05	0.04

(1) Includes condensables.
(2) Compliance with this limit will ensure compliance with 45CSR§§2-4.1. and -4.1.2.
(3) Compliance with this limit will ensure compliance with 45CSR§§10-3.1. and -3.1.5.

e. At the time operation of the Duct Burners commences, the permittee shall have, and make available to the Director upon request, guarantees from the appropriate equipment vendors that the following maximum emission rates are achievable from the Duct Burners:

Table 15.1.2.e.: Duct Burner Vendor Guarantee Requirements (in ppmvd at 15% O_2)

Pollutant	Requirement
CO	2.0
NO_X	2.0
VOC	1.0

f. The Duct Burners shall each not combust in excess of 610.81 mmscf of fuel gas per year.

g. **45CSR2**

The Duct Burners are subject to the applicable limitations and standards under 45CSR2, including the requirements as given below under paragraphs g.1. through 5. of this condition.

1. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than 10 percent opacity based on a six-minute block average.
[45CSR§2-3.1.]

2. Compliance with the visible emission requirements of 45CSR§2-3.1. shall be determined in accordance with 40 CFR 60, Appendix A, Method 9 and 45CSR16 or by using measurements from continuous opacity monitoring systems approved by the Secretary. The Secretary may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of 45CSR§2-3.1. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.
[45CSR§2-3.2.]

3. No person shall cause, suffer, allow or permit the discharge of particulate matter into the open air from all fuel burning units located at one plant, measured in terms of pounds per hour in excess of the amount determined as follows:

   i. For Type "b" fuel burning units, the product of 0.09 and the total design heat inputs for such units in MMBtu/hr, provided however that no more than 600 lb/hr of particulate matter shall be discharged into the open air from all such units.

   [45CSR§§2-4.1. and -4.1.2.]

4. The addition of sulfur oxides to a combustion unit exit gas stream for the purpose of improving emissions control equipment efficiency shall be reviewed by the Secretary. No person shall cause, suffer, allow or permit the addition of sulfur oxides as described above unless written approval for such addition is provided by the Secretary.
[45CSR§2-4.4.]

5. At all times, including periods of startups, shutdowns and malfunctions, owners and operators shall, to the extent practicable, maintain and operate any fuel burning unit(s) 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 Secretary which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source.
[45CSR§2-9.2.]

h. **45CSR10**

The Duct Burners are subject to the applicable limitations and standards under 45CSR10, including the requirements in paragraph h.1. of this condition.

1. No person shall cause, suffer, allow or permit the discharge of sulfur dioxide into the open air from all stacks located at one plant, measured in terms of pounds per hour, in excess of the amount determined as follows:

   i. For Type "b" fuel burning units, the product of 3.1 and the total design heat inputs for such units discharging through those stacks in MMBtu/hr.

[45CSR§§10-3.1. and -3.1.5.]

[45CSR13, R13-3493, 4.1.3.a. to h.; 45CSR2; 45CSR10]

15.1.3. **40 CFR 60, Subpart KKKK**

The Combustion Turbines and Duct Burners shall meet all applicable requirements under 40 CFR 60, Subpart KKKK including the following:

a. The permittee must meet the emission limits for NO_X specified in Table 1 to Subpart KKKK of Part 60.

Table 1 to Subpart KKKK of Part 60 – Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Heat Input at Peak Load (HHV)	NO_X Emission Standard
New turbine firing natural gas	> 50 MMBtu/hr and ≤ 850 MMBtu/hr	25 ppm at 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh)
Turbines operating at less than 75 percent of peak load and turbines operating at temperatures less than 0°F	> 30 MW output	96 ppm at 15 % O_2 or 590 ng/J of useful output (4.7 lb/MWh)

[45CSR16; 40 CFR §60.4320(a); Table 1 to Subpart KKKK of Part 60]

b. The permittee must meet the emission limits for SO_2 specified in either paragraphs b.1. or 2. of this condition.

1. The permittee must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or

2. The permittee must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[45CSR16; 40 CFR §§60.4330(a), (a)(1), and (a)(2)]

c. The permittee must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. **[45CSR16; 40 CFR §60.4333(a)]**

[45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.1.4. **Control Devices**

Use of SCR systems and oxidation catalysts shall be in accordance with the following:

a. The SCR systems and oxidation catalysts shall be designed, operated and maintained according to good engineering practices and manufacturing recommendations so as to achieve, at a minimum, the following limits on each emission unit:

1. LM6000PG

i. NO_X: 2.0 ppmvd at 15% O_2

ii. CO: 2.0 ppmvd at 15% O_2

iii. VOCs: 1.0 ppmvd at 15% O_2

2. SGT-800

i. NO_X: 1.75 ppmvd at 15% O_2

ii. CO: 0.5 ppmvd at 15% O_2

iii. VOCs: 0.5 ppmvd at 15% O_2

iv. Formaldehyde: 0.1 ppmvd at 15% O_2

3. Duct Burner

i. NO_X: 2.0 ppmvd at 15% O_2

ii. CO: 2.0 ppmvd at 15% O_2

iii. VOCs: 1.0 ppmvd at 15% O_2

b. Catalyst performance shall be monitored and catalysts replaced according to good engineering practices and manufacturing recommendations.

c. The permittee shall operate each SCR in the optimal aqueous ammonia injection range as determined according to manufacturer recommendations or during the required performance testing. Ammonia/Urea slip from each SCR shall not exceed 5 ppmvd at 15% O_2.

[45CSR13, R13-3493, 4.1.7.a. to c.]

15.1.5. **45CSR40**

The Combustion Turbines must meet all applicable requirements for ozone season NO_X emissions under 45CSR40, including the following:

a. Ozone Season NO_X Emission Limitation – The owner or operator of a unit that meets the applicability requirements set forth in 45CSR§40-4.1. shall limit emissions of NO_X during an ozone season pursuant to a NO_X emission rate for each unit contained in Condition 4.1.2.e. of R13-3493.
[45CSR§40-5.1.]

b. The owner or operator of an applicable unit under 45CSR§40-4.1. shall install and operate a certified continuous emission monitoring system (CEMS) as necessary to attribute ozone season mass emissions of NO_X to each unit in accordance with 45CSR§40-6.5. Nitrogen oxides mass emissions measurements recorded and reported in accordance with 45CSR§40-6.5. shall be used to determine a unit's compliance with the ozone season NO_X emission limitation set forth in 45CSR§40-5.
[45CSR§40-6.1.]

c. An owner or operator of a combustion turbine unit that elects to demonstrate compliance using a CEMS shall meet the following requirements:

1. Install and certify the CEMS in accordance with Performance Specification 2 in Appendix B to 40 CFR 60 and 45CSR16;

2. Conduct the performance tests in accordance with 40 CFR §60.4400;

3. Operate and maintain the CEMS in accordance with 40 CFR §60.4345 on a continuous basis;

4. Collect all CEMS data in accordance with 40 CFR §60.4350;

5. For each month of the ozone season:

i. Determine total monthly heat input (in MMBtu) using fuel flowmeters and measurements or records of fuel gross calorific value, or in instances where fuel flow is not metered determine total monthly heat input (in MMBtu) from other measurements and records; and

ii. Calculate total monthly NO_X mass emissions (in tons) by multiplying the total monthly heat input by the 30-day rolling average NO_X emission rate (in lb/MMBtu) determined under 45CSR§§40-6.5.c. and -6.5.d. for the last day of the month on which the unit operated and divide by 2,000;

6. Determine the total NO_X mass emissions for the ozone season (in tons) by summing the amounts of total monthly NO_X mass emissions calculated under 45CSR§40-6.5.e. for each month of the ozone season; and

7. Comply with the following reporting and recordkeeping requirements:

i. Maintain records in accordance with 40 CFR §60.49b and all additional records necessary to support the heat input data, 30-day rolling average NO_X emission rate data, and NO_X mass emissions computations described in 45CSR§§40-6.5.e. and -6.5.f.; and

ii. Submit to the Secretary reports in accordance with 40 CFR §60.49b and include the total monthly heat input data, 30-day rolling average NO_X emission rate data, and monthly and ozone season NO_X mass emissions computations described in 45CSR§§40-6.5.e. and -6.5.f.

[45CSR§40-6.5.]

15.2. Monitoring Requirements

15.2.1. **Startup/Shutdowns.** For the purposes of demonstrating compliance with the maximum startup and shutdown operating hours as given under 15.1.1.f., the permittee shall monitor and record the monthly and rolling twelve (12) month total of hours each CT is operating in startup and shutdown mode. The record shall show the distinct hours of operation in each mode. "Startup" and "Shutdown" shall be defined as those periods where the exhaust temperature of the CTs is not sufficient for the SCR's and Oxidation Catalysts to effectively meet the limitations given under 15.1.4.
[45CSR13, R13-3493, Condition 4.2.3.]

15.2.2. **Grid Power Distribution.** For the purposes of demonstrating compliance with the maximum power export limitations as given under 15.1.1.h., the permittee shall monitor and record the monthly and rolling twelve (12) month total watts (in MW) exported to the power grid (i.e., not used for on-site power).
[45CSR13, R13-3493, Condition 4.2.4.]

15.2.3. **Duct Burner Fuel Usage.** For the purposes of demonstrating compliance with the maximum Duct Burner fuel usage limitations as given under 15.1.2.f., the permittee shall monitor and record the monthly and rolling twelve (12) month total of the volume of fuel used in each Duct Burner.
[45CSR13, R13-3493, Condition 4.2.5.]

15.2.4. a. **CEMS.** Within 60 days after achieving the maximum power generation rate at which the facility will be operated, but no later than 180 days after initial startup, the permittee shall, to show continuous compliance with the NO_X emission limits as given under Conditions 15.1.1.e., 15.1.1.g., 15.1.2.d., 15.1.2.e., and 15.1.4., install and operate a Continuous Emissions Monitoring System (CEMS) for monitoring the emissions of NO_X from each Combustion Turbine and Duct Burner. The CEMS shall be installed, maintained, and operated according to the applicable requirements given under 40 CFR 60, Subpart KKKK and any additional subparts referenced thereto. Data recorded by the CEMS shall be kept for a period not less than three (3) years and shall be made available to the Director or his/her representative upon request.
[45CSR13, R13-3493, Condition 4.2.6.; 45CSR§30-5.1.c.]

b. **40 CFR 60, Subpart KKKK Requirements for the NO_X CEMS.**

1. The permittee must install, calibrate, maintain, and operate the CEMS as described in 40 CFR §§60.4335(b) and 60.4345.

i. Install, certify, maintain and operate a CEMS consisting of a NO_X monitor and diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu).
[40 CFR §§60.4335(b) and (b)(1)]

ii. The following requirements for the NO_X CEMS equipment must be met:

a. Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in 40 CFR 60, Appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in 40 CFR 60, Appendix F is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to 40 CFR 75, Appendix A is acceptable for use under 40 CFR 60, Subpart KKKK. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

b. As specified in 40 CFR §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

c. Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to 40 CFR 75 are acceptable for use under 40 CFR 60, Subpart KKKK.

d. Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

e. The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs a., c., and d. of this condition. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in Section 1 of Appendix B to 40 CFR 75.

[40 CFR §60.4345]

[40 CFR §§60.4340(b) and (b)(1)]

2. For the purposes of identifying excess emissions using the continuous emission monitoring equipment:

i. All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).

ii. For each unit operating hour in which a valid hourly average, as described in 40 CFR §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of 40 CFR 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

iii. Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

iv. If the permittee has installed and certified a NO_X diluent CEMS to meet the requirements of 40 CFR 75, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under 40 CFR 60, Subpart KKKK. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c).

v. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

vi. Calculate the hourly average NO_X emission rates, in units of the emission standards under 40 CFR §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output-based standard.

a. For simple-cycle operation:

$$E = \frac{(NO_X)_h \times (HI)_h}{P} \quad \text{Eq. 1}$$

Where:
E = hourly NO_X emission rate, in lb/MWh,
$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,
$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in Appendix D to 40 CFR 75, and
P = gross energy output of the combustion turbine in MW.

b. For combined-cycle and combined heat and power complying with the output-based standard, use Eq. 1 in this condition, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad \text{Eq. 2}$$

Where:
P = gross energy output of the stationary combustion turbine system in MW,
$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW, and
$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW.

$$Ps = \frac{Q \times H}{3.413 \times 10^6\ Btu/MWh} \quad \text{Eq. 3}$$

Where:
Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electrical or mechanical output, in MW,
Q = measured steam flow rate in lb/hr,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions Btu/lb, and
3.413×10^6 = conversion from Btu/hr to MW, and
Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

c. For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL \times AL} \quad \text{Eq. 4}$$

Where:
E = NO_X emission rate in lb/MWh,
$(NO_X)_m$ = NO_X emission rate in lb/hr,
BL = manufacturer's base load rating of turbine, in MW, and
AL = actual load as a percentage of the base load.

vii. For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph f. of this condition to assess excess emissions on a 4-hour rolling average basis, as described in 40 CFR §60.4380(b)(1).

viii. For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph f. of this condition to assess excess emissions on a 30 unit operating day rolling average basis, as described in 40 CFR §60.4380(b)(1).

[40 CFR §60.4350]

[45CSR16; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.2.5. **45CSR2 Visual Emission Monitoring.** At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with 15.1.2.g. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.
[45CSR13, R13-3493, 4.2.7.]

15.2.6. **Control Devices.** The permittee shall meet the following monitoring, compliance demonstration, recording, and reporting requirements for the oxidation catalysts:

a. The permittee shall regularly inspect, properly maintain and/or replace catalytic reduction devices to ensure functional and effective operation of each unit. The permittee shall ensure proper operation, maintenance and performance of catalytic reduction devices by following the catalyst manufacturer emissions related operating and maintenance recommendations, or develop, implement, or follow a site-specific maintenance plan.

b. To demonstrate compliance with paragraph a. of this condition., the permittee shall maintain a copy of the site-specific maintenance plan or manufacturer maintenance plan.

[45CSR13, R13-3493, 4.2.8.]

15.2.7. **40 CFR 60, Subpart KKKK Requirements for SO_2 Monitoring.**

a. The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. The permittee must use one of the sources of information specified in paragraph a.1. of this condition to make the required demonstration:

1. The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet.

[40 CFR §§60.4365 and 60.4365(a)]

b. The permittee must conduct an initial performance test, as required in 40 CFR §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies listed in 40 CFR §60.4415(a) that the permittee may use to conduct the performance tests.

1. The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility.

[40 CFR §§60.4415(a) and (a)(1)]

[45CSR16; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.2.8. **CAM Compliance Demonstration for CO Emissions.** At all times that the turbines and/or duct burners are in operation, the catalyst bed inlet temperature shall be monitored via thermocouple. The thermocouple shall have a minimum accuracy within the range of ±0.01% to ±0.25% of the span. The temperature data shall be monitored and recorded every 24 hours of operation.

For the purposes of CAM, an excursion shall be defined as follows:

a. Prior to the initial performance test, an excursion occurs when the inlet temperature is outside of the manufacturer's recommended range. The expected catalyst bed operating temperature is 650°F to 700°F.

b. Following the initial performance test, an excursion occurs when the inlet temperature is outside of the range established in the performance test.

[45CSR§30-5.1.c.; 40 CFR §64.6(c)]

15.2.9. **Commencement of Operation.** The owner or operator shall conduct the monitoring required under 40 CFR 64 upon issuance of a part 70 or 71 permit that includes such monitoring, or by such later date specified in the permit pursuant to 40 CFR §64.6(d).
[45CSR§30-5.1.c.; 40 CFR §64.7(a)]

15.2.10. **Proper Maintenance.** At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.
[45CSR§30-5.1.c; 40 CFR §64.7(b)]

15.2.11. **Continued Operation.** Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of 40 CFR 64, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR§30-5.1.c.; 40 CFR §64.7(c)]

15.2.12. **Response to Excursions or Exceedances.**

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[45CSR§30-5.1.c.; 40 CFR §64.7(d)]

15.2.13. **Documentation of Need for Improved Monitoring.** After approval of monitoring under 40 CFR 64, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the 40 CFR 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

[45CSR§30-5.1.c.; 40 CFR §64.7(e)]

15.2.14. **Quality Improvement Plan (QIP).** Based on the results of the determination made under Condition 15.2.12.b., the Administrator or the permitting authority may require the permittee to develop and implement a QIP. If required, the QIP shall be developed and implemented in accordance with 40 CFR §§64.8(b) through (e).
[45CSR§30-5.1.c.; 40 CFR §64.8]

15.3. Testing Requirements

15.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established in this permit and/or applicable regulations.
[45CSR13, R13-3493, 4.3.1.]

15.3.2. **Combustion Turbines/Duct Burners.** The permittee shall meet the following performance testing requirements with respect to the combustion turbines (CT):

a. The permittee shall, pursuant to the timing and other requirements of 40 CFR 60, Subpart KKKK, conduct, or have conducted, performance testing on each CT and Duct Burner to determine the emission rates of NO_X, during operation in non-startup/shutdown mode (as defined under 15.2.1.). The testing shall, in addition to meeting all applicable requirements under 40 CFR 60, Subpart KKKK, be in accordance with 3.3.1. Results of the performance testing shall, unless granted in writing a waiver by the Director, be used to determine compliance with the NO_X emission limits given under 15.1.1.e. and 15.1.2.d. After the initial test, subsequent NO_X performance testing shall be conducted annually (no more than 14 months following the previous test) unless the previous results demonstrate that the affected units achieved compliance of less than or equal to 75 percent of the applicable emission limits, then the permittee may reduce the frequency of subsequent tests to once every two years (no more than 26 calendar months following the previous test); and
[45CSR16; 40 CFR §60.4340(a)]

b. In addition to the required performance testing under 15.3.2.a., the permittee shall, within 60 days after achieving the maximum capacity each CT/Duct Burner combination will be operated, but not later than 180 days after initial startup, conduct, or have conducted, a performance test on each CT and Duct Burner to determine compliance with the emission limits of CO, during operation in non-startup/shutdown mode as defined 15.1.1.e. After the initial tests, subsequent performance testing on CO shall be conducted annually (no more than 14 months following the previous test) unless the previous results demonstrate that the affected units achieved compliance of less than or equal to 75 percent of the applicable emission limits, then the permittee may reduce the frequency of subsequent tests to once every two years (no more than 26 calendar months following the previous test). The permittee shall use the test methods specified in Table 15.3.2.b. unless granted approval in writing by the Director to use an alternative test method in a protocol submitted pursuant to 3.3.1.c.

Table 15.3.2.b.: Combustion Turbine Test Methods

Pollutant	Test Method[(1)]
CO	Method 10B

(1) All test methods refer to those given under 40 CFR 60, Appendix A.

For the purposes of CAM, an exceedance occurs when the performance test results demonstrate that the CO emissions from the oxidation catalyst surpass the CO concentration limits in Condition 15.1.4.a. of this operating permit.

[45CSR§30-5.1.c.; 40 CFR §64.6(c)]

[45CSR13, R13-3493, 4.3.2.]

15.3.3. **NO_X Performance Testing under 40 CFR 60, Subpart KKKK.**

a. The permittee must conduct an initial performance test, as required in 40 CFR §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

1. There are two general methodologies that the permittee may use to conduct the performance tests. For each test run:

i. Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in Appendix A to 40 CFR 60. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in Appendix A to 40 CFR 60, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} \times (NO_X)_c \times Q_{std}}{P}$$

Where:
E = NO_X emission rate, in lb/MWh
1.194×10^{-7} = conversion constant, in lb/dscf-ppm
$(NO_X)_c$ = average NO_X concentration for the run, in ppm
Q_{std} = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR §60.4350(f)(2); or

ii. Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in Appendix A of 40 CFR 60. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in Appendix A of 40 CFR 60 to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in 40 CFR §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

2. Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe

designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

3. Notwithstanding paragraph a.2. of this condition, the permittee may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in Appendix A of 40 CFR 60 if the following conditions are met:

i. The permittee may perform a stratification test for NO_X and diluent pursuant to

a. The procedures specified in section 6.5.6.1(a) through (e) of Appendix A of 40 CFR 75.

ii. Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

a. If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5 ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then the permittee may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

b. For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, the permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

c. For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, the permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1 ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

b. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. The permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The permittee must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

1. If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

2. For combined cycle and combined heat and power turbine systems with supplemental heat (duct burner), the permittee must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

3. If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the permittee chooses to monitor the steam or water to fuel ratio in accordance with 40 CFR §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable 40 CFR §60.4320 NO_X emission limit.

4. Compliance with the applicable emission limit in 40 CFR §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in 40 CFR §60.4320.

5. If the permittee elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR §60.4405) as part of the initial performance test of the affected unit.

6. The ambient temperature must be greater than 0°F during the performance test.

[45CSR16; 40 CFR §60.4400; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.3.4. **Alternative Initial NO_X Performance Testing under 40 CFR 60, Subpart KKKK.** If a NO_X-diluent CEMS is installed and certified in accordance with 40 CFR §60.4345, then the initial performance test required under 40 CFR §60.8 may be performed in the following alternative manner:

a. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

b. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

c. Use the test data both to demonstrate compliance with the applicable NO_X emission limit under 40 CFR §60.4320 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR §60.4335.

d. Compliance with the applicable emission limit in 40 CFR §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

[45CSR16; 40 CFR §60.4405; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.3.5. **Testing Requirements for the Duct Burners under 45CSR2.**

a. At such reasonable times as the Secretary may designate, the owner or operator of any fuel burning unit(s) may be required to conduct or have conducted tests to determine the compliance of such unit(s) with the emission limitations of 15.1.2.g. Such tests shall be conducted in accordance with the appropriate method set forth in Appendix 45-2 to 45CSR2 or other equivalent EPA approved method approved by the Secretary. The Secretary may at his option witness or conduct such tests. Should the Secretary exercise his option to conduct such tests, the operator will provide all necessary sampling connections and sampling ports located in such manner as the Secretary may require, power for test

equipment, and the required safety equipment such as scaffolding, railings and ladders to comply with generally accepted good safety practices.

1. Sufficient information on temperatures, velocities, pressures, weights and dimensional values shall be reported to the Secretary, with such necessary commentary as he may require to allow an accurate evaluation of the reported test results and the conditions under which they were obtained.

b. The Secretary may conduct such other tests as he may deem necessary to evaluate air pollution emissions other than those noted in 45CSR§2-4.1.

[45CSR§§2-8.1.2., and -8.1.3.]

15.4. Recordkeeping Requirements

15.4.1. For the purpose of demonstrating compliance with any visible emissions monitoring required by the Director, the permittee shall maintain records documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s). For an emission unit out of service during the evaluation, the record of observation may note "out of service" (O/S) or equivalent.
[45CSR13, R13-3493, 4.4.2.]

15.4.2. **Recordkeeping Requirements for the Duct Burners under 45CSR2.**

a. The owner or operator shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each fuel burning unit as specified in paragraph a.1. of this condition. Such records are to be maintained on-site and made available to the Secretary upon request.

1. For fuel burning unit(s) which burn only pipeline quality natural gas, such records shall include, but not be limited to, the date and time of startup and shutdown, and the quantity of fuel consumed on a monthly basis.

[45CSR§2-8.3.3.; 45CSR§§2A-7.1.a. and -7.1.a.1.]

15.4.3. **General Recordkeeping Requirements under CAM.**

a. The owner or operator shall comply with the recordkeeping requirements specified in 40 CFR §70.6(a)(3)(ii). The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 CFR §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under 40 CFR 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[45CSR§30-5.1.c.; 40 CFR §64.9(b)]

15.5. Reporting Requirements

15.5.1. **Reporting Requirements for Duct Burners under 45CSR2**

The owner or operator of a fuel burning unit(s) subject to this rule shall report to the Secretary any malfunction of such unit or its air pollution control equipment which results in any excess particulate matter emission rate or excess opacity (i.e., emissions exceeding the standards in 45CSR§§2-3 and -4 as provided in one of the following subdivisions:

a. Excess opacity periods meeting the following conditions may be reported on a quarterly basis unless otherwise required by the Secretary:

1. The excess opacity period does not exceed 30 minutes within any 24-hour period; and

2. Excess opacity does not exceed 40%.

b. The owner or operator shall report to the Secretary any malfunction resulting in excess particulate matter or excess opacity, not meeting the criteria set forth in paragraph a. of this condition, by telephone or e-mail by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Secretary within 30 days providing the following information:

1. A detailed explanation of the factors involved or causes of the malfunction;

2. The date and time of duration (with starting and ending times) of the period of excess emissions;

3. An estimate of the mass of excess emissions discharged during the malfunction period;

4. The maximum opacity measured or observed during the malfunction;

5. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and

6. A detailed explanation of the corrective measures or programs that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.]

15.5.2. **40 CFR 60, Subpart KKKK Reporting Requirements**

a. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under 40 CFR 60, Subpart KKKK, the permittee must submit reports

of excess emissions and monitor downtime, in accordance with 40 CFR §60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.
[40 CFR §60.4375(a)]

b. For each affected unit that performs annual performance tests in accordance with 40 CFR §60.4340(a), the permittee must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.
[40 CFR §60.4375(b)]

c. For the purpose of reports required under 40 CFR §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

1. For turbines using continuous emission monitoring, as described in 40 CFR §60.4335(b) and §60.4345:

i. An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in 40 CFR §60.4320. For the purposes of 40 CFR 60, Subpart KKKK, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of 40 CFR 60, Subpart KKKK, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

ii. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee will use this information for compliance purposes.

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

[40 CFR §60.4380(b)]

d. All reports required under 40 CFR §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.
[40 CFR §60.4395]

[45CSR16; 45CSR13, R13-3493, 4.1.2.i. and 4.1.3.i.]

15.5.3. **General Reporting Requirements under CAM.**

a. On and after the date specified in 40 CFR §64.7(a) by which the owner or operator must use monitoring that meets the requirements of 40 CFR 64, the owner or operator shall submit monitoring reports to the permitting authority in accordance with 40 CFR §70.6(a)(3)(iii).

b. A report for monitoring under 40 CFR 64 shall include, at a minimum, the information required under 40 CFR §70.6(a)(3)(iii) and the following information, as applicable:

1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

3. A description of the actions taken to implement a QIP during the reporting period as specified in 40 CFR §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[45CSR§30-5.1.c.; 40 CFR §64.9(a)]

15.6. Compliance Plan

15.6.1. None

16.0 NPP: Fuel Gas Heaters [emission unit ID(s): FH1 and FH2]

16.1. Limitations and Standards

16.1.1. **Fuel Gas Heaters**

The Fuel Gas Heaters, identified as FH1 and FH2, shall each not exceed an MDHI of 9.90 MMBtu/hr, and shall only be fired by pipeline-quality natural gas, ethane, or some combination thereof. The boilers shall operate in accordance with the following:

a. The maximum emissions from each Fuel Gas Heater shall not exceed the limits given in the following table:

Table 16.1.1.a.: Per-Fuel Gas Heater Emission Limits

Pollutant	lb/hr	ton/year
CO	0.82	3.57
NO_X	0.49	2.13
$PM_{2.5}$/PM_{10}/PM	0.07	0.32
SO_2	0.01	0.03
VOC	0.05	0.23

b. As the annual emission limits given under Table 16.1.1.a. are based on the Fuel Gas Heaters operating 8,760 hours per year, there are no annual restrictions on the fuel combusted or hours of operation for the units.

[45CSR13, R13-3493, 4.1.4.a. and c.]

16.1.2. **45CSR2 – Visible Emissions Monitoring**

a. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than 10 percent opacity based on a six-minute block average.
[45CSR13, R13-3493, 4.1.4.d.; 45CSR§2-3.1.]

b. Compliance with the visible emission requirements of 45CSR§2-3.1. shall be determined in accordance with 40 CFR 60, Appendix A, Method 9 and 45CSR16 or by using measurements from continuous opacity monitoring systems approved by the Secretary. The Secretary may require the installation, calibration, maintenance and operation of continuous opacity monitoring systems and may establish policies for the evaluation of continuous opacity monitoring results and the determination of compliance with the visible emission requirements of 45CSR§2-3.1. Continuous opacity monitors shall not be required on fuel burning units which employ wet scrubbing systems for emission control.
[45CSR§2-3.2.]

16.2. Monitoring Requirements

16.2.1. **45CSR2 Visual Emission Monitoring.** At such reasonable times as the Secretary may designate, the permittee shall conduct Method 9 emission observations for the purpose of demonstrating compliance with 16.1.2.a. Method 9 shall be conducted in accordance with 40 CFR 60, Appendix A.
[45CSR13, R13-3493, 4.2.7.]

16.3. Testing Requirements

16.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established in the permit and/or applicable regulations.
[45CSR13, R13-3493, 4.3.1.]

16.4. Recordkeeping Requirements

16.4.1. For the purpose of demonstrating compliance with any visible emissions monitoring required by the Director, the permittee shall maintain records documenting the date and time of each visible emission check, the emission point or equipment/source identification number, the name or means of identification of the observer, the results of the check(s), whether the visible emissions are normal for the process, and, if applicable, all corrective measures taken or planned. The permittee shall also record the general weather conditions (i.e. sunny, approximately 80°F, 6-10 mph NE wind) during the visual emission check(s). For an emission unit out of service during the evaluation, the record of observation may note "out of service" (O/S) or equivalent.
[45CSR13, R13-3493, 4.4.2.]

16.5. Reporting Requirements

16.5.1. None

16.6. Compliance Plan

16.6.1. None

17.0 NPP: Emergency Generator and Emergency Fire Pump Engine [emission unit ID(s): EG1 and FP1]

17.1. Limitations and Standards

17.1.1. **Emergency Generator and Emergency Fire Pump**

The Emergency Generator and Emergency Fire Pump, identified as EG1 and FP1, respectively, shall meet the following requirements:

a. The Emergency Generator shall not exceed 1,676 HP, shall be fired only with diesel fuel with a maximum sulfur content not to exceed 0.05%, and shall not operate in excess of 100 hours per year during times not defined as emergencies. The Emergency Fire Pump shall not exceed 700 HP, shall be fired only with diesel fuel with a maximum sulfur content not to exceed 0.05%, and shall not operate in excess of 100 hours per year during times not defined as emergencies.

b. The maximum emissions from the Emergency Generator shall not exceed the limits given in the following table:

Table 17.1.1.b.: Emergency Generator Emission Limits

Pollutant	lb/hr	ton/year
CO	12.13	0.61
NO_X	16.45	0.82
PM[(1)]	0.77	0.04
SO_2	3.43	0.17
VOCs	5.60	0.28
HAPs	0.01	0.01

(1) All particulate matter emissions are assumed to be $PM_{2.5}$ or smaller. Includes condensables.

c. The maximum emissions from the Emergency Fire Pump shall not exceed the limits given in the following table:

Table 17.1.1.c.: Emergency Fire Pump Emission Limits

Pollutant	lb/hr	ton/year
CO	5.07	0.25
NO_X	4.29	0.21
PM[(1)]	0.32	0.02
SO_2	1.44	0.07
VOCs	1.46	0.07
HAPs	0.01	0.01

(1) All particulate matter emissions are assumed to be $PM_{2.5}$ or smaller. Includes condensables.

d. **40 CFR 60, Subpart IIII Based Not-to-Exceed (NTE) Standards.** Pursuant to the language given under 40 CFR §60.4205(e), the Emergency Generator and the Emergency Fire Pump are subject to the following NTE Standards:

Table 17.1.1.d.: Subpart IIII NTE Standards

Engine Type	Emission Standards					
	NMHC + NO_X		CO		PM	
	g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr
Emergency Generator	8.0	6.0	4.4	3.3	0.25	0.19
Fire Pump	5.0	3.7	4.4	3.3	0.25	0.19

[45CSR13, R13-3493, 4.1.5.a. to d.]

17.1.2. **40 CFR 60, Subpart IIII**

The Emergency Generator and the Emergency Fire Pump are subject to all applicable requirements under 40 CFR 60, Subpart IIII, including the following:

a. **Emergency Generator (EG1).** Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in 40 CFR §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

1. Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in 40 CFR §§60.4202(a)(1) through (2).

i. For engines with a rated power greater than or equal to 37 kW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR 1039, Appendix I, for all pollutants and the smoke standards as specified in 40 CFR §1039.105 beginning in model year 2007.

[40 CFR §§60.4202(a) and (a)(2)]

2. **Table 17.1.2.a.: Emergency Generator Emission Standards**

Engine	Table 2 to Appendix I of 40 CFR 1039 Tier 2 Emission Standards (g/kW-hr)		
	NO_X + NMHC	**CO**	**PM**
Emergency Generator Rated Power > 560 kW; Starting Model Year 2006	6.4	3.5	0.20

[Table 2 to Appendix I of 40 CFR 1039]

[40 CFR §60.4205(b)]

b. **Emergency Fire Pump (FP1).** Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 to Subpart IIII of 40 CFR 60, for all pollutants.

Table 17.1.2.b.: Emergency Fire Pump (FP1) Emission Standards

Maximum Engine Power	Model Year(s)	Table 4 to Subpart IIII of 40 CFR 60 Emission Standards for Stationary Fire Pump Engines					
		NMHC + NO_X		**CO**		**PM**	
		g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr	g/kW-hr	g/HP-hr
450 ≤ kW ≤ 560 (600 ≤ HP ≤ 750)	2009+	4.0	3.0	3.5	2.6	0.20	0.15

[40 CFR §60.4205(c); Table 4 to Subpart IIII of 40 CFR 60]

c. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR §60.4205 over the entire life of the engine.
[40 CFR §60.4206]

d. Owners and operators of stationary CI ICE subject to 40 CFR 60, Subpart IIII with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.
[40 CFR §60.4207(b)]

e. For an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, the permittee must install a non-resettable hour meter prior to startup of the engine.
[40 CFR §60.4209(a)]

f. For a stationary CI internal combustion engine subject to the emission standards in 40 CFR 60, Subpart IIII, the permittee must do all of the following, except as permitted under 40 CFR §60.4211(g):

1. Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

2. Change only those emission-related settings that are permitted by the manufacturer; and

3. Meet the requirements of 40 CFR 1068, as applicable.

[40 CFR §60.4211(a)]

g. For the Emergency Generator and the Emergency Fire Pump, the permittee must comply by purchasing an engine certified to the emission standards in 40 CFR §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR §60.4211(g).
[40 CFR §60.4211(c)]

h. For an emergency stationary ICE, the permittee must operate the emergency stationary ICE according to the requirements in 40 CFR §§60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in 40 CFR §§60.4211(f)(1) through (3), is prohibited. If the permittee does not operate the engine according to the requirements in 40 CFR §§60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and must meet all requirements for non-emergency engines.

1. There is no time limit on the use of emergency stationary ICE in emergency situations.

2. The permittee may operate the emergency stationary ICE for the purpose specified in 40 CFR §60.4211(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR §60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR §60.4211(f)(2).

i. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

3. Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in 40 CFR §60.4211(f)(2). Except as provided in 40 CFR §60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a

facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

i. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

a. The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

b. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

c. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

d. The power is provided only to the facility itself or to support the local transmission and distribution system.

e. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[40 CFR §60.4211(f)]

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16]

17.1.3. **40 CFR 63, Subpart ZZZZ**
An affected source that meets any of the criteria in 40 CFR §§63.6590(c)(1) through (7) must meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines, or 40 CFR 60, Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under 40 CFR 63.
[45CSR13, R13-3493, 4.1.5.f.; 45CSR34; 40 CFR §§63.6590(c) and (c)(1)]

17.2. Monitoring Requirements

17.2.1. None

17.3. Testing Requirements

17.3.1. At such reasonable time(s) as the Secretary may designate, in accordance with the provisions of 3.3. of this permit, the permittee shall conduct or have conducted test(s) to determine compliance with the emission limitations established in the permit and/or applicable regulations.
[45CSR13, R13-3493, 4.3.1.]

17.3.2. **40 CFR 60, Subpart IIII – Testing Requirements**

a. If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as follows:

1. For a stationary CI internal combustion engine with a maximum engine power greater than 500 HP, the permittee must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution practice for minimizing emissions. In addition, the permittee must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after the emission-related settings are changed in a way that is not permitted by the manufacturer. The permittee must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[40 CFR §§60.4211(g) and (g)(3)]

b. Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to 40 CFR 60, Subpart IIII must do so according to 40 CFR §§60.4212(a) through (e).

1. The performance test must be conducted according to the in-use testing procedures in 40 CFR 1039, Subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR 1042, Subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR 1039, Appendix I, or with Tier 2 emission standards in 40 CFR 1042, Appendix I, may follow the testing procedures specified in 40 CFR §60.4213, as appropriate.

2. Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR §1039.101(e) and 40 CFR §1039.102(g)(1), except as specified in 40 CFR §1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR 1039.

3. Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR 1039, Appendix I, or Tier 2 emission standards as described in 40 CFR 1042, Appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$NTE\ requirement\ for\ each\ pollutant = (1.25) \times (STD)$$

Where:
STD = The standard specified for that pollutant in 40 CFR 1039 or 1042, as applicable.

[40 CFR §§60.4212(a) to (c)]

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16]

17.4. Recordkeeping Requirements

17.4.1. 40 CFR 60, Subpart IIII – Recordkeeping Requirements

a. If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in Table 5 to Subpart IIII of 40 CFR 60, if the emergency engine does not meet the standards applicable to the non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16; 40 CFR §60.4214(b)]

17.5. Reporting Requirements

17.5.1. 40 CFR 60, Subpart IIII – Reporting Requirements

a. For an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in 40 CFR §60.4211(f)(3)(i), the permittee must submit an annual report according to the requirements in 40 CFR §§60.4211(d)(1) through (3).

1. The report must contain the following information:

i. Company name and address where the engine is located.

ii. Date of the report and beginning and ending dates of the reporting period.

iii. Engine site rating and model year.

iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

v. Hours spent for operation for the purposes specified in 40 CFR §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR

§60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

2. Annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

3. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to 40 C.F.R. 60, Subpart IIII is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR §60.4. Beginning on February 26, 2025, submit annual report electronically according to 40 CFR §60.4214(g).

[45CSR13, R13-3493, 4.1.5.e.; 45CSR16; 40 CFR §60.4214(d)]

17.6. Compliance Plan

17.6.1. None

18.0 NPP: Storage Tanks [emission unit ID(s): OT1 to OT8, AT1, WS1 to WS4, GT1 to GT4, FT1, and FT2]

18.1. Limitations and Standards

18.1.1. **Storage Tanks**
Tank size and material stored shall be limited as specified in the table titled "Natrium Power Plant" in Section 1.1. of this operating permit.
[45CSR13, R13-3493, 4.1.6.]

18.2. Monitoring Requirements

18.2.1. None

18.3. Testing Requirements

18.3.1. None

18.4. Recordkeeping Requirements

18.4.1. None

18.5. Reporting Requirements

18.5.1. None

18.6. Compliance Plan

18.6.1. None

19.0 NPP: Component Leaks

19.1. Limitations and Standards

19.1.1. **Component Leaks**
The permittee shall mitigate the release of fugitive emissions according to the following requirements:

a. The permittee shall, within 180 days of facility startup, submit a modification or Class II Administrative Update, as applicable pursuant to 45CSR13, to revise the number and type of components (valves, pump seals, connectors, etc.) in gas/vapor service or light liquid service (as applicable) listed in Attachment N of Permit Application R13-3493 or any amendments or revisions submitted thereto if the as-built number of components results in calculated VOC or HAP emissions in excess of those given under Attachment N.

[45CSR13, R13-3493, 4.1.8.]

19.2. Monitoring Requirements

19.2.1. None

19.3. Testing Requirements

19.3.1. None

19.4. Recordkeeping Requirements

19.4.1. None

19.5. Reporting Requirements

19.5.1. None

19.6. Compliance Plan

19.6.1. None

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Fri, Jun 13, 2025 at 12:01 PM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>, "Thornberry, Jill" <Jill.Thornberry@williams.com>

Sarah,

Thank you for your assistance with the Title V renewal for the Natrium Gas Plant. Williams has yet to purchase EG1, but in all likelihood the engine will exhibit a displacement less than 10 liters per cylinder. Therefore, Williams respectfully requests incorporation of the emission standards referenced in 40 CFR 60.4202(a)(2). In the unlikely event that Williams purchases an engine with a displacement greater than 10 liters per cylinder, Williams will submit an administrative modification to update the emissions standards.

Please let us know if you need anything further.

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Wed, Jun 11, 2025 at 11:01 AM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>, "Thornberry, Jill" <Jill.Thornberry@williams.com>

Chris,

Thanks for getting back to me about those questions. I'm hoping to send you a copy of the pre-draft permit and fact sheet to review by the end of this week, or early next week at the latest.

Before that, however, please provide the displacement of the emergency generator EG1. In the application's emission unit form for EG1, the emission standards of 40 C.F.R. 60.4205(c) and Table 4 to Subpart IIII were stated to be applicable, but these standards are only applicable to fire pump engines. As a model year 2007+ emergency stationary CI ICE with a displacement of less than 30 liters per cylinder and that is not a fire pump engine, EG1 would be subject to 60.4205(b) which refers to the emission standards in 60.4202. The emission standard under 60.4202 that will be applicable is dependent on the engine's displacement relative to values for the displacement other than 30 liters per cylinder.

Please let me know if you have any questions.

Thanks,
- Sarah

[Quoted text hidden]

You are viewing this page over a secure connection. Click here for more information.

West Virginia Secretary of State — Online Data Services

Business and Licensing

Online Data Services Help

Business Organization Detail

NOTICE: The West Virginia Secretary of State's Office makes every reasonable effort to ensure the accuracy of information. However, we make no representation or warranty as to the correctness or completeness of the information. If information is missing from this page, it is not in the The West Virginia Secretary of State's database.

BLUE RACER MIDSTREAM, LLC

Organization Information

Org Type	Effective Date	Established Date	Filing Date	Charter	Class	Sec Type	Termination Date	Termination Reason
LLC | Limited Liability Company	12/20/2012		12/20/2012	Foreign	Profit			

Organization Information

Business Purpose	2212 - Utilities - Utilities - Natural Gas Distribution	**Capital Stock**	
Charter County		**Control Number**	99Y8J
Charter State	DE	**Excess Acres**	
At Will Term	A	**Member Managed**	MGR
At Will Term Years		**Par Value**	
Authorized Shares		**Young Entrepreneur**	Not Specified

Addresses

Type	Address
Designated Office Address	5949 SHERRY LANE, SUITE 1700 DALLAS, TX, 75225
Mailing Address	ONE WILLIAMS CENTER-MD-47 TULSA, OK, 74172 USA
Notice of Process Address	C T CORPORATION SYSTEM 5098 WASHINGTON ST W STE 407 CHARLESTON, WV, 253131561
Principal Office Address	ONE WILLIAMS CENTER-MD-47 TULSA, OK, 74172 USA
Type	**Address**

Officers

Type	Name/Address
Manager	DANILO M. JUVANE ONE WILLIAMS CENTER-MD-47 TULSA, OK, 74172
Manager	GARY D. REAVES II ONE WILLIAMS CENTER-MD-47 TULSA, OK, 74172
Type	**Name/Address**

Mergers

Merger Date	Merged	Merged State	Survived	Survived State
3/6/2014	BLUE RACER NATRIUM, LLC	DE	BLUE RACER MIDSTREAM, LLC	DE
Merger Date	**Merged**	**Merged State**	**Survived**	**Survived State**

Date	Amendment
3/6/2014	MERGER: MERGING BLUE RACER NATRIUM, LLC, A QUALIFIED DE LIMITED LIABILITY COMPANY WITH AND INTO BLUE RACER MIDSTREAM, LLC, A QUALIFIED DE LIMITED LIABILITY COMPANY, THE SURVIVOR
Date	**Amendment**

Annual Reports

Filed For
2025
2024
2023
2022
2021
2020
2019
2018
2017
2016
2015
2014
2013
Date filed

For more information, please contact the Secretary of State's Office at 304-558-8000.

Tuesday, June 17, 2025 — 7:36 AM

© 2025 State of West Virginia

UC Defaulted Accounts Search Results

Sorry, no records matching your criteria were found.

FEIN:
Business name: BLUE RACER MIDSTREAM, LLC
Doing business as/Trading as:

Please use your browsers back button to try again.

WorkforceWV	Unemployment Compensation	Offices of the Insurance Commissioner

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Fri, May 30, 2025 at 12:03 PM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>, "Thornberry, Jill" <Jill.Thornberry@williams.com>

Hello Sarah,

Here are the answers to the questions you had sent over regarding the Natrium P&F Title V permit renewal application:

1. As stated on Page 2 of 8 of the CAM Plan, Williams will install, operate, and maintain a CEMS in accordance with 40 CFR 60, Subpart KKKK; therefore, 45CSR40-6.5 is the appropriate citation.
2. For the CAM Plan to monitor CO emissions from the turbines and duct burners: Combination of the duct burners as well as the turbines.
    a. The catalytic oxidizer will control the combined, comingled emissions from both the turbine and the duct burner to a maximum concentration of 2 ppmvd at 15% O2. The performance test will measure the concentration of CO in the combined, comingled exhaust from the catalytic oxidizer. Therefore, any performance test measurement greater than 2 ppmvd of CO at 15% O2 would be considered an exceedance. The CAM plan does not require any revisions.
    b. The catalyst bed operating temperate range would be approximately 650 to 700 F but is subject to change based on the specific manufacturer recommendations for the equipment that is installed.
    c. The thermocouples accuracy is +/- .01% to +/-.25% of the span
    d. Williams will collect one measurement for each 24-hour period of operation. If Williams personnel record more than one measurement during a given 24-hour period (e.g., due to a shift change), these readings would be averaged before comparing to the acceptable temperature range.
    e. The thermocouple will be calibrated annually.
3. The thermocouple will be calibrated annually.
4. The displacement for EG1 and FP1 is less than 30 liters per cylinder.
5. This is correct, S058 each fire pump engine is rated at 800 HP.
6. The true vapor pressure of the gasoline stored in tanks TK-3802 to TK-6802 is less than 11.1 psia. The true vapor pressure of the refrigerated propane stored in TK-7802 is less than 11.1 psia. For all of these tanks, Williams will use a closed vent system to comply with the requirements in 40 CFR 60.112c(a)(1) and 40 CFR 60.112c(d). The closed vent system for TK-3802 to TK-6802 will route emissions to a fuel gas system. The closed vent system for TK-7802 will route emissions to a process.
7. Thank you for updating the Emission Units Table, yes, the Spherical NGL Storage Tanks US-2800, US-2801, US-2804, and US-2805 and the Pressurized NGL Bullet Tanks V-2905, V-2915, V-2925, and V-2935 should also indicate that they have not been constructed yet.
8. Yes, there would be electric-driven reciprocating compressors associated with FUG AREA 5 to FUG AREA 7 that would likely be subject to OOOOb regulations.

Thank you and have a great weekend,

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Thu, May 15, 2025 at 12:17 PM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>, "Thornberry, Jill" <Jill.Thornberry@williams.com>

Chris,

I understand if more time is needed to respond to all of these questions. However, please provide a response as soon as practicable and, if possible, by the end of this month. Due to the deadline to have this renewal permit issued, the EPA and public comment periods for the permit need to begin by the end of June, at the latest. Although you will have the opportunity to provide comments during the public comment period, I'd like for you to have a chance to review the pre-draft permit and fact sheet prior to the comment periods due to the number of revisions that are being made.

Please keep me updated, and let me know if you have any questions.

Thanks,
- Sarah
[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Thu, May 15, 2025 at 10:49 AM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>, "Thornberry, Jill" <Jill.Thornberry@williams.com>

Sarah,

Thank you for your assistance with the renewal of the Title V operating permit for the Natrium Gas Plant. Addressing certain of the questions in your 5/12/25 and 5/15/25 emails will require correspondence with vendors, manufacturers, and consultants. Therefore, Williams respectfully requests additional time to provide responses to these questions. Williams will aim to provide a response by June 20, 2025. Williams appreciates WVDEP's consideration of this request.

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Thu, May 15, 2025 at 10:00 AM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>

I have a few additional questions that I need to ask:

7) Based on the 2024 Title V Annual Report, I've updated the Emission Units Table's "Year Installed" for the following units to "Not Yet Constructed":

a) Regeneration Gas Heaters - S040, S044, S048
b) Cryogenic HMO Heaters - S041, S045, S049
c) Hot Oil Heaters - S052, S053
d) Stabilizer Heater - S056
e) Natural Gasoline Storage Tanks - TK-3802 to TK-6802
f) Refrigerated Propane Storage Tank - TK-7802
g) Slop Tank - TK-2906
h) Produced Water Tank - TK-2907
i) Ethane Amine Regenerator - S054
j) Fugitive Areas - FUG AREA 5 to FUG AREA 7

Are there any other emission units that should be identified as "Not Yet Constructed"? Specifically, I wanted to check on the status of the Spherical NGL Storage Tanks US-2800, US-2801, US-2804, and US-2805 and the Pressurized NGL Bullet Tanks V-2905, V-2915, V-2925, and V-2935 which were initially permitted at the same time as these other units but were not mentioned in the 2024 Title V Annual Report.

8) As you stated, the fugitive areas FUG AREA 5 to FUG AREA 7 would be subject to 40 C.F.R. Part 60, Subpart OOOOb once constructed. I'm currently working on incorporating the Subpart OOOOb requirements for process units into the operating permit, but I wanted to check if any further electric reciprocating compressors will be constructed for these areas that will be subject to the Subpart OOOOb requirements for reciprocating compressors?

Thanks,
- Sarah

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Mon, May 12, 2025 at 1:33 PM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>

Thanks for the update. I have some further questions for the application. Please provide a response as soon as practicable but preferably no later than Tuesday, May 20, 2025.

1) Section 2.10.7 of the regulatory applicability section in the Title V application's overview specifies that "45CSR40-6.1. requires a certified CEMS to attribute ozone season NOx mass emissions to each unit in accordance with 40 C.F.R. Part 75, Subpart H." This appears to have been carried over from Section 3.2.1 of the regulatory applicability section in the application overview for R13-3493. However, 45CSR40 has been revised since R13-3493 was issued, and I wanted to get some clarification on the operation of the CEMS under this rule. 45CSR40-6.1. now allows for compliance with the ozone season NOx emission limitation to be demonstrated through the installation and operation of a certified CEMS as necessary to attribute ozone season mass emissions of NOx to each unit in accordance with 45CSR40-6.2. through -6.5.

> 45CSR40-6.2. is applicable to an owner or operator that elects to demonstrate compliance in accordance with 40 C.F.R. Part 75, Subpart H. This section references the provisions of Subpart H for the monitoring, recordkeeping, and reporting requirements.
>
> 45CSR40-6.5. is specifically applicable to an owner or operator of a combustion turbine unit that elects to demonstrate compliance using a CEMS. This section references the provisions of 40 C.F.R. Part 60, Subpart KKKK for the testing of the turbines and the operation of the CEMS with some further requirements for recordkeeping and reporting of the NOx ozone season emissions.

Please let me know whether 45CSR40-6.2. or 45CSR40-6.5. will be met to demonstrate compliance with the 45CSR40 ozone season NOx requirements.

2) For the CAM Plan to monitor CO emissions from the turbines and duct burners:

> a) In the application's CAM Plan, an exceedance of the CO emission limits was defined as a performance test showing CO emissions greater than the manufacturer's guaranteed emissions from the turbines (2 ppmvd at 15% O2 for LM6000PG or 0.5 ppmvd at 15% O2 for SGT-800) (Conditions 4.1.2.g. and 4.1.7.a. of R13-3493). In Conditions 4.1.3.e. and 4.1.7.a. of R13-3493, the duct burners have a separate manufacturer guarantee for CO emissions (2 ppmvd at 15% O2). Since the duct burners will be operated with the turbines during performance testing, I wanted to clarify if the exceedance definition given in the application's CAM Plan accounts for the CO emissions from the duct burners as well as the turbines or if the definition of an exceedance under the CAM Plan needs to be revised to account for the duct burner emissions?
>
> b) What is the manufacturer's recommended temperature range for the catalyst bed inlet that will be used to determine if an excursion occurs prior to the first performance testing?
>
> c) What is the minimum accuracy of the thermocouple?
>
> d) The application includes that data will be collected **at least once** every 24-hour period and that a 24-hour block average will be used. At what interval (every 15-minutes, every hour, etc.) will temperature data be collected during each 24-hour period to determine the average?
>
> e) How often will the thermocouple be calibrated?

3) For the flare S004A's CAM Plan, the frequency that the thermocouple is calibrated and maintained should be included in the CAM Plan's QA/QC Practices. How often will the thermocouple be calibrated?

4) What is the displacement of the engines EG1 and FP1?

5) I also wanted to confirm that you had said that the two fire pump engines that make up emission unit S058 each have a rating of 800 HP?

6) To determine the applicability of certain Subpart Kc requirements, what is the true vapor pressure (psia) of the gasoline stored in the tanks TK-3802 to TK-6802 and the propane stored in TK-7802?

Please let me know if you have any questions or if you would like to discuss any of these topics further.

Thanks,
- Sarah

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Wed, May 7, 2025 at 8:07 AM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>

Hi Sarah,

After a discussion with my upper management we would like to keep the power generation in our Title V permit. The plan is to build this still based on market forecast for the need in the coming years.

Additionally, we understand that the not-yet-constructed tanks and fugitive areas would fall under Kc and OOOOb regulations once constructed.

If there was anything missing based on our discussion, please reach out.

Thank you,

Chris

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Fri, May 2, 2025 at 4:37 PM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>

Meeting Info for the Title V Permit Renewal for Blue Racer Midstream, LLC's Natrium Extraction and Fractionation Processing Plant:

To join the video meeting, click this link: https://meet.google.com/ain-xcki-tnk
Otherwise, to join by phone, dial +1 707-404-8108 and enter this PIN: 812 105 169#
To view more phone numbers, click this link: https://tel.meet/ain-xcki-tnk?hs=5

Please let me know if you have any issues joining the meeting.

- Sarah

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Fri, May 2, 2025 at 4:21 PM
To: "Hortert, Chris" <Chris.Hortert@williams.com>
Cc: DJ Wheeler <dwheeler@trinityconsultants.com>

Hi, Chris.

Monday at 3 PM works for me. I'll send you a link for the meeting shortly. Please, let me know if you don't receive it.

Thanks,
- Sarah
[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Hortert, Chris <Chris.Hortert@williams.com> Fri, May 2, 2025 at 5:45 AM
To: "Barron, Sarah K" <sarah.k.barron@wv.gov>, DJ Wheeler <dwheeler@trinityconsultants.com>

Hi Sarah,

Can you meet Monday May 5th at 3 p.m.? If that works you can send a meeting invite, or let me know and I will send the meeting invite.

Thank you,

Chris Hortert

Chris Hortert, P.G. | Williams | Environmental Specialist | Ohio River Supply Hub
Mobile: 412-452-1893 |



**Registered in Pennsylvania*

If you have received this message in error, please reply to advise the sender of the error and then immediately delete this message.

From: Barron, Sarah K <sarah.k.barron@wv.gov>
Sent: Thursday, May 1, 2025 2:02 PM
To: DJ Wheeler <dwheeler@trinityconsultants.com>; Hortert, Chris <Chris.Hortert@williams.com>
Subject: [EXTERNAL] Title V Permit Renewal; R30-05100142-2025

CAUTION! EXTERNAL SENDER STOP. ASSESS. VERIFY!! If suspicious, STOP and click the Phish Alert Button

[Quoted text hidden]

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal; R30-05100142-2025

Barron, Sarah K <sarah.k.barron@wv.gov> Thu, May 1, 2025 at 2:02 PM
To: dwheeler@trinityconsultants.com, chris.hortert@williams.com

DJ Wheeler and Chris Hortert,

I have some questions related to the Title V permit renewal application for Blue Racer Midstream, LLC's Natrium Extraction and Fractionation Processing Plant. Would either of you have time to speak with me on Monday (05/05) or Tuesday (05/06)?

Thanks,
- Sarah

--
Sarah Barron
Engineer Trainee
West Virginia Department of Environmental Protection
Division of Air Quality
(304) 414-1915
sarah.k.barron@wv.gov

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal - Request for Information - Application No. R30-05100142-2024

DJ Wheeler <dwheeler@trinityconsultants.com> Wed, Oct 2, 2024 at 12:54 PM
To: "sarah.k.barron@wv.gov" <sarah.k.barron@wv.gov>
Cc: "Hortert, Chris" <Chris.Hortert@williams.com>

Sarah,

On behalf of Blue Racer Midstream, LLC and in response to your 9/17/24 email regarding the Title V permit renewal application for the Natrium Gas Processing Plant, please find attached the requested Attachment E: Emission Unit Forms. Please let us know if you have any questions.

Thanks,

DJ Wheeler

Managing Consultant

P 614.568.8851 M 231.670.3072

Email: dwheeler@trinityconsultants.com

440 Polaris Pkwy, Suite 275 Westerville, OH 43082

Connect with us: LinkedIn / Facebook / Twitter / YouTube / trinityconsultants.com

Stay current on environmental issues. Subscribe today to receive Trinity's free *EHS Quarterly*.

From: Barron, Sarah K <sarah.k.barron@wv.gov>
Sent: Tuesday, September 17, 2024 11:18 AM
To: Hortert, Chris <Chris.Hortert@williams.com>
Subject: [EXTERNAL] Title V Permit Renewal - Request for Information - Application No. R30-05100142-2024

CAUTION! EXTERNAL SENDER STOP. ASSESS. VERIFY!! If suspicious, STOP and click the Phish Alert Button

[Quoted text hidden]

Attachment E 20241002.pdf
678K

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
AT1	Ammonia Tank	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

60,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	N/A	N/A
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	N/A	N/A
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FH1 and FH2	Fuel Gas Heater #1 and Fuel Gas Heater #2 (9.9 MMBtu/hr each)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fuel Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
TBD		

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

9.9 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 9.9 MMBtu/hr	**Type and Btu/hr rating of burners:** 9.9 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
7,296 scf/hr
64 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	1,357 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.82	3.57
Nitrogen Oxides (NO_X)	0.49	2.13
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.07	0.32
Particulate Matter (PM_{10})	0.07	0.32
Total Particulate Matter (TSP)	0.07	0.32
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.28E-04	3.19E-03
N-Hexane	6.11E-05	2.68E-04
Total HAPs	9.20E-04	4.03E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 13, Permit R13-3493
Condition 4.1.4 – MDHI for the unit shall not exceed 9.9 mmBtu/hr

Condition 4.1.4.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.49	2.13
CO	0.82	3.57
$PM_{2.5}$ / PM_{10} / PM(1)	0.07	0.32
VOCs	0.05	0.23
SO2	0.01	0.03

(1) Includes condensables

Condition 4.1.4.d – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-3493
Condition 4.2.1. – Compliance with the maximum design capacity limitations as given under 4.1. shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a throughput or production rate that does not exceed the specified value under 4.1.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FT1	Generator Fuel Tank	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

25 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	See note "a" below	See note "a" below
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	See note "a" below	See note "a" below
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

a. **Pursuant to 45CSR13, Table 45-13B, defined as a de minimis source but included here for completeness.**

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FT2	Fire Pump Fuel Tank	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

25 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	See note "a" below	See note "a" below
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	See note "a" below	See note "a" below
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

a. **Pursuant to 45CSR13, Table 45-13B, defined as a de minimis source but included here for completeness.**

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
GT1, GT2, GT3, and GT4	Glycol Tank #1, Glycol Tank #2, Glycol Tank #3, and Glycol Tank #4	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

1,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	See note "a" below	See note "a" below
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	See note "a" below	See note "a" below
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

a. **Pursuant to 45CSR13, Table 45-13B, defined as a de minimis source but included here for completeness.**

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
OT1, OT2, OT3, and OT4	Lubricating Oil Tank #1, Lubricating Oil Tank #2, Lubricating Oil Tank #3, and Lubricating Oil Tank #4	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

5,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	See note "a" below	See note "a" below
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	See note "a" below	See note "a" below
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

a. **Pursuant to 45CSR13, Table 45-13B, defined as a de minimis source but included here for completeness.**

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
OT5, OT6, OT7, and OT8	Waste Oil Tank #1, Waste Oil Tank #2, Waste Oil Tank #3, and Waste Oil Tank #4	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

250 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	See note "a" below	See note "a" below
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	See note "a" below	See note "a" below
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

a. **Pursuant to 45CSR13, Table 45-13B, defined as a de minimis source but included here for completeness.**

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
WS1, WS2, WS3, and WS4	Washout Sump #1, Washout Sump #2, Washout Sump #3, and Washout Sump #4	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

250 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	See note "a" below	See note "a" below
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	See note "a" below	See note "a" below
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 7.1.

a. **Pursuant to 45CSR13, Table 45-13B, defined as a de minimis source but included here for completeness.**

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493
Condition 4.1.6 – Tank size and material stored shall be limited as specified under Table 1.0 of R13-3493

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. Permit R13-3493

Condition 4.2.1 - Compliance with the maximum design capacity limitations shall be based on a clear and visible boilerplate rating or on product literature, manufacturer's data, or equivalent documentation that shows that the specific emission unit(s) or processing line in question is limited by design to a capacity that does not exceed the specified value under Table 1.0 of R13-3493.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

Barron, Sarah K <sarah.k.barron@wv.gov>

Title V Permit Renewal - Request for Information - Application No. R30-05100142-2024

Barron, Sarah K <sarah.k.barron@wv.gov> Tue, Sep 17, 2024 at 11:17 AM
To: chris.hortert@williams.com

Chris Hortert,

In the Title V permit renewal application for the Natrium Extraction and Fractionation Processing Plant, the storage tanks permitted under R13-3493 (OT1 to OT8, AT1, WS1 to WS4, GT1 to GT4, and FT1 to FT2) and the fuel gas heaters permitted under R13-3493 (FH1 and FH2) were listed as insignificant activities. However, the storage tanks are subject to applicable requirements under Condition 4.1.6. of R13-3493, and the heaters are subject to applicable requirements under 45CSR2 and Condition 4.1.4. of R13-3493. Therefore, these emission units cannot be considered insignificant activities. Please, submit the Attachment E: Emission Unit Forms for these units.

Thanks,
- Sarah

--
Sarah Barron
Engineer Trainee
West Virginia Department of Environmental Protection
Division of Air Quality
(304) 414-1915
sarah.k.barron@wv.gov

Barron, Sarah K <sarah.k.barron@wv.gov>

Completeness Determination, Natrium Extraction and Fractionation Processing Plant (NPP), Application No. R30-05100142-2024

2 messages

Barron, Sarah K <sarah.k.barron@wv.gov> Wed, Sep 4, 2024 at 8:43 AM
To: t.j.rinke@williams.com, chris.hortert@williams.com

Your Title V renewal application for a permit to operate the above referenced facility was received by this Division on August 19, 2024. After review of said application, it has been determined that the application is administratively complete as submitted. Therefore, the above referenced facility qualifies for an Application Shield.

The applicant has the duty to supplement or correct the application. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft permit.

The submittal of a complete application shall not affect the requirement that any source have all **preconstruction permits** required under the rules of the Division.

If during the processing of this application it is determined that additional information is necessary to evaluate or take final action on this application, a request for such information will be made in writing with a reasonable deadline for a response. Until which time as your renewal permit is issued or denied, please continue to operate this facility in accordance with 45CSR30, section 6.3.c. which states: *If the Secretary fails to take final action to deny or approve a timely and complete permit application before the end of the term of the previous permit, the permit shall not expire until the renewal permit has been issued or denied, and any permit shield granted for the permit shall continue in effect during that time.* This protection shall cease to apply if, subsequent to the completeness determination made pursuant to paragraph 6.1.d. of 45CSR30 and as required by paragraph 4.1.b., the applicant fails to submit by the deadline specified in writing any additional information identified as being needed to process the application.

Please remember, **failure of the applicant to timely submit information required or requested to process the application may cause the Application Shield to be revoked.** Should you have any questions regarding this determination, please contact me.

Sincerely,

Sarah Barron

--
Sarah Barron
Engineer Trainee
West Virginia Department of Environmental Protection
Division of Air Quality
(304) 414-1915
sarah.k.barron@wv.gov

Hortert, Chris <Chris.Hortert@williams.com> Wed, Sep 4, 2024 at 9:48 AM
To: "sarah.k.barron@wv.gov" <sarah.k.barron@wv.gov>

Your message

To: Hortert, Chris
Subject: [EXTERNAL] Completeness Determination, Natrium Extraction and Fractionation Processing Plant (NPP), Application No. R30-05100142-2024
Sent: Wednesday, September 4, 2024 8:43:31 AM (UTC-05:00) Eastern Time (US & Canada)

was read on Wednesday, September 4, 2024 9:48:25 AM (UTC-05:00) Eastern Time (US & Canada).

Received
August 19, 2024
WV DEP/Div of Air Quality

Division of Air Quality Permit Application Submittal

Please find attached a permit application for : Blue Racer Midstream, LLC; Proctor, WV
[Company Name; Facility Location]

- DAQ Facility ID (for existing facilities only): 051-00142
- Current 45CSR13 and 45CSR30 (Title V) permits associated with this process (for existing facilities only): R13-2896K; R13-3493; R30-05100142-2020(M003)

- Type of NSR Application (check all that apply):
  - ☐ Construction
  - ☐ Modification
  - ☐ Class I Administrative Update
  - ☐ Class II Administrative Update
  - ☐ Relocation
  - ☐ Temporary
  - ☐ Permit Determination

- Type of 45CSR30 (TITLE V) Application:
  - ☐ Title V Initial
  - ☑ Title V Renewal
  - ☐ Administrative Amendment**
  - ☐ Minor Modification**
  - ☐ Significant Modification**
  - ☐ Off Permit Change

****If the box above is checked, include the Title V revision information as ATTACHMENT S to the combined NSR/Title V application.**

- Payment Type:
  - ☐ Credit Card (Instructions to pay by credit card will be sent in the Application Status email.)
  - ☑ Check (Make checks payable to: WVDEP – Division of Air Quality)
    Mail checks to:
    WVDEP – DAQ – Permitting
    Attn: NSR Permitting Secretary
    601 57th Street, SE
    Charleston, WV 25304

Please wait until DAQ emails you the Facility ID Number and Permit Application Number. Please add these identifiers to your check or cover letter with your check.

- If the permit writer has any questions, please contact (all that apply):
  - ☐ Responsible Official/Authorized Representative
    - Name:
    - Email:
    - Phone Number:
  - ☑ Company Contact
    - Name: Chris Hortert
    - Email: Chris.Hortert@williams.com
    - Phone Number: 412-452-1893
  - ☐ Consultant
    - Name:
    - Email:
    - Phone Number:

BLUE RACER MIDSTREAM, LLC – NATRIUM EXTRACTION AND FRACTIONATING PROCESSING PLANT / NATRIUM POWER PLANT

Proctor, West Virginia

Trinity Consultants

TABLE OF CONTENTS

1. APPLICATION OVERVIEW 1-1
   - 1.1 Introduction 1-1
   - 1.2 Facility Description 1-2
   - 1.3 Updates to Title V Operating Permit 1-2
   - 1.4 Organization of Application 1-3

2. REGULATORY APPLICABILITY 2-1
   - 2.1 New Source Review Classification 2-1
   - 2.2 Title V Operating Permit Program 2-2
   - 2.3 New Source Performance Standards 2-2
     - 2.3.2 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial Steam Generating Units 2-2
     - 2.3.3 40 CFR 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) 2-3
     - 2.3.4 40 CFR 60, Subpart OOOO —Standards of Performance for Crude Oil and Natural Gas Facilities 2-3
     - 2.3.5 40 CFR 60, Subpart OOOOa —Standards of Performance for Crude Oil and Natural Gas Facilities 2-3
     - 2.3.6 40 CFR 60, Subpart OOOOb —Standards of Performance for Crude Oil and Natural Gas Facilities 2-3
     - 2.3.7 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines 2-3
     - 2.3.8 40 CFR 60, Subpart KKKK —Standards of Performance for Stationary Combustion Turbines 2-4
     - 2.3.9 40 CFR 60, Subpart TTTT —Greenhouse Gas Emissions for Electric Utility Steam Generating Units 2-4
   - 2.4 National Emission Standards for Hazardous Air Pollutants 2-4
     - 2.4.1 40 CFR 63, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities 2-5
     - 2.4.2 40 CFR 63, Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers 2-5
     - 2.4.3 40 CFR 63, Subpart UUUUUU – Coal and Oil-fired Electric Utility Steam Generating Units 2-5
     - 2.4.4 40 CFR 63, Subpart YYYY – Stationary Combustion Turbines 2-5
     - 2.4.5 40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) 2-5
   - 2.5 Cross State Air Pollution Rule 2-5
   - 2.6 Acid Rain Regulations 2-6
   - 2.7 Compliance Assurance Monitoring 2-6
   - 2.8 Chemical Accident Prevention 2-6
   - 2.9 Stratospheric Ozone Protection Regulations 2-6
   - 2.10 West Virginia SIP Regulations 2-7
     - 2.10.1 45CSR2 – To Prevent and Control Particulate Matter Air Pollution From Combustion of Fuel in Indirect Heat Exchangers 2-7
     - 2.10.2 45CSR6 – To Prevent and Control Air Pollution from Combustion of Refuse 2-7
     - 2.10.3 45CSR10 – To Prevent and Control Air Pollution from the Emission of Sulfur Oxides 2-7

2.10.4 45CSR13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation 2-8
2.10.5 45CSR16 – Standards of Performance for New Stationary Sources..... 2-8
2.10.6 45CSR22 – Air Quality Management Fee Program 2-8
2.10.7 45CSR40 – Control of Ozone Season Nitrogen Oxide Emissions 2-8
2.10.8 45CSR34 – Emission Standards for Hazardous Air Pollutants 2-8

3. WVDAQ APPLICATION FOR A TITLE V OPERATING PERMIT RENEWAL 3-1

ATTACHMENT A: AREA MAP A

ATTACHMENT B: PLOT PLAN B

ATTACHMENT C: PROCESS FLOW DIAGRAMS C

ATTACHMENT D: EQUIPMENT TABLE D

ATTACHMENT E: EMISSION UNIT FORMS E

ATTACHMENT G: AIR POLLUTION CONTROL DEVICE FORMS G

ATTACHMENT H: COMPLIANCE ASSURANCE MONITORING (CAM) PLAN H

APPENDIX A. PTE CALCULATIONS

APPENDIX B. CAM APPLICABILITY ANALYSIS

1. APPLICATION OVERVIEW

1.1 Introduction

Blue Racer Midstream, LLC (Blue Racer) owns the Natrium Extraction and Fractionation Processing Plant (NPP) located in Proctor, WV which is operated by Williams MLP Operating, LLC. The facility currently operates under Title V Operating Permit R30-05100142-2020(MM03) originally issued April 14, 2020 by the West Virginia Department of Environmental Protection (WVDEP). The current Title V Operating Permit expires April 14, 2025; therefore, Blue Racer is required to submit a Title V Operating Permit renewal application by October 14, 2024. With this application, Blue Racer is requesting a renewal of the Title V Operating Permit for the NPP Plant in accordance with Title 45, Legislative Rule of the Division of Air Quality (DAQ) Series (CSR) 30-4.1.a.3.

1.2 Facility Description

NPP is an extraction and fractionation processing plant that utilizes cryogenic plants. The facility processes raw natural gas by separating and fractionating natural gas liquids (NGLs). Inlet gas and NGLs are sent to the site via pipeline, truck, railcar, or barge. Under R13-2896K, Blue Racer is authorized to install and operate Cryogenic Processing Trains #1-7 including all associated heaters, piping components, product storage, and product transfer activities. Under R13-3493, Blue Racer is authorized to install and operate the Natrium Power Plant which is a nominal 230 mega-Watt (mW) gas-fired combined heat and power plant designed to provide heat duty and electrical power to the existing co-located NPP. NPP and the Natrium Power Plant are considered a single stationary source under the Title V permitting program.

1.3 Updates to Title V Operating Permit

The Title V Operating Permit will need to be updated to include the equipment associated with the Natrium Power Plant, as permitted in Permit R13-3493, issued December 15, 2020.

Blue Racer also requests that the permit include additional monitoring and recordkeeping for the catalytic oxidizers used to control carbon monoxide (CO) emissions from the turbines at the Natrium Power Plant in order to satisfy the requirements of the Compliance Assurance Monitoring (CAM) program in Title 40, Code of Federal Regulations, Part 64 (40 CFR 64).

1.4 Organization of Application

This Title V Operating Permit renewal application contains the following elements:

- Section 2: Regulatory Applicability
- Section 3: WVDAQ Application Forms
- Attachment A: Area Map
- Attachment B: Plot Plan
- Attachment C: Process Flow Diagrams
- Attachment D: Equipment Table
- Attachment E: Emission Unit Forms
- Attachment G: Air Pollution Control Device Forms
- Attachment H: Compliance Assurance Monitoring (CAM) Plan
- Appendix A: PTE Calculations
- Appendix B: CAM Applicability Analysis

2. REGULATORY APPLICABILITY

A key objective of a Title V operating permit application is to compile all applicable Clean Air Act derived requirements into one document. The requirements can be categorized as: (1) emission limits and work practice standards; and (2) testing, monitoring, recordkeeping, and reporting requirements. To compile a list of the requirements applicable to a facility, it is first necessary to determine which Federal and State air regulations apply to the facility as a whole, or to individual emission units. This section documents the applicability determinations made for Federal and State air quality regulations. Regulations potentially applicable are detailed in Section 2 and in the "Applicable Requirements" forms provided by WVDEP.

Additional details on applicability for several regulations are presented in this section. Specifically, applicability or non-applicability of the following regulatory programs is addressed:

- New Source Review (NSR) Permitting;
- Title V of the 1990 Clean Air Act Amendments;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Acid Rain Program;
- Compliance Assurance Monitoring (CAM);
- Risk Management Plan (RMP);
- Stratospheric Ozone Protection; and
- West Virginia State Implementation Plan (SIP) Regulations

This review is presented to supplement and/or add clarification to the information provided in the WVDEP Title V application forms which fulfill the requirement to include citations and descriptions of applicable statutory and administrative code requirements. In addition to providing a summary of applicable requirements, this section of the application also provides non-applicability determinations for certain regulations, allowing WVDEP to confirm that identified regulations are not applicable. \

2.1 New Source Review Classification

NPP and the Natrium Power Plant are located in Marshall County which has been designated as "in-attainment" or "unclassifiable" with the National Ambient Air Quality Standards (NAAQS) for all pollutants. NPP and the Natrium Power Plant are considered a single stationary source for the purposes of the major NSR program. Gas Processing Plants are not on the list of 28 source categories in 45CSR14 2.43.a.; thus, NPP is subject to the general 250 ton per year (tpy) "major" source PSD threshold. Facility-wide potential emissions of certain pollutants from NPP are greater than the major source threshold of 250 tpy. Therefore, the facility is considered an existing major source.

Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input are classified as one of the 28 listed source categories in 45CSR14 2.43.a. with a 100 ton per year (tpy) "major" source PSD threshold. Potential emissions from the Natrium Power Plant are less than the major source threshold; therefore, the Natrium Power Plant is considered a nested existing minor source.

2.2 Title V Operating Permit Program

The requirements of 40 CFR 70 establish the federal Title V operating permit program. West Virginia has incorporated the provisions of this federal program as part of the SIP under 45CSR30. The major source thresholds with respect to the West Virginia Title V operating permit program regulations are 10 tons per year (tpy) of a single hazardous air pollutant (HAP), 25 tpy of any combination of HAPs, and 100 tpy of all other regulated pollutants. NPP and the Natrium Power plant are considered a single stationary source for the purposes of the Title V program. The potential emissions of at least one regulated pollutant exceed the corresponding threshold(s). Therefore, the facility is classified as a major source for Title V purposes. As described in Section 1.1, Blue Racer is submitting this timely and complete renewal application by the submission deadline of October 14, 2024 (i.e., six months prior to the expiration of the current Title V Operating Permit) in accordance with 45CSR30-4.1.a.3.

2.3 New Source Performance Standards

The federal NSPS require new, modified, or reconstructed sources to control emissions to the level that is achievable by the best demonstrated technology as specified in the applicable provisions of the rule. The following summary describes the applicability and non-applicability of NSPS subparts relevant to NPP and the Natrium Power Plant.

2.3.1 40 CFR 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The affected source under 40 CFR 60, Subpart Db (NSPS Db) is each steam generating unit for which construction, modification, or reconstruction is commenced after June 19, 1984, and that has a maximum design heat input capacity of greater than 100 million British thermal units per hour (MMBtu/hr).

As provided in 40 CFR 60.41b, a steam-generating unit is defined as:

"…a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart."

NPP's Hot Oil Heater S001 has a rating of 216.7 MMBtu/hr and is subject to the requirements of NSPS Db. Blue Racer will continue to operate a continuous emissions monitoring system (CEMS) to demonstrate compliance with the emission limitations for nitrogen oxides (NO_X) established in NSPS Db.

2.3.2 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial Steam Generating Units

The affected source under 40 CFR 60, Subpart Dc (NSPS Dc) is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989, and that has a maximum design heat input capacity of 100 million British thermal units per hour (MMBtu/hr) or less, but greater than or equal to 10 MMBtu/hr. NSPS Dc contains emission standards for SO_2 and PM.

As provided in 40 CFR 60.41c, a steam-generating unit is defined as:

"…a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart."

NPP's Hot Oil Heaters S016-2019 and S052-S053 are each rated at 61.58 MMBtu/hr and are subject to NSPS Dc. The Cryogenic HMO heaters (S013, S026, S037, S045, S049) rated at 26.3 MMBtu/hr and S041 rated at 54.67 MMBtu/hr are subject to NSPS Dc, as well as the Stabilizer Heater (S056) rated at 10.09 MMBtu/hr. Blue Racer will continue to maintain records of fuel usage to satisfy the requirements of NSPS Dc.

2.3.3 40 CFR 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)

Affected sources under 40 CFR 60, Subpart Kb (NSPS Kb) include storage vessels with a capacity greater than or equal to 75 cubic meters (19,812.9 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. The Natural Gasoline Storage tanks (TK-802, TK-2802, TK-3802, TK-4802, TK-5802, and TK-6802) and the refrigerated propane storage tank (TK-7802) at NPP are subject the requirements of NSPS Kb including the closed vent system and control device requirements.

2.3.4 40 CFR 60, Subpart OOOO —Standards of Performance for Crude Oil and Natural Gas Facilities

40 CFR 60 Subpart OOOO (NSPS OOOO), Standards of Standards of Performance for Crude Oil and Natural Gas Facilities, applies to affected facilities that commenced construction, reconstruction, or modification after August 23, 2011, and on or before September 18, 2015. NPP has various reciprocating compressors that are affected facilities under NSPS OOOO.

2.3.5 40 CFR 60, Subpart OOOOa —Standards of Performance for Crude Oil and Natural Gas Facilities

Subpart OOOOa, Standards of Standards of Performance for Crude Oil and Natural Gas Facilities, applies to affected facilities that commenced construction, reconstruction, or modification after September 18, 2015. NPP has various reciprocating compressors that are affected facilities under NSPS OOOOa. The piping components in FUG AREA 1 through FUG AREA 7 are subject to the leak detection and repair requirements outlined in NSPS OOOOa for onshore natural gas processing plants.

2.3.6 40 CFR 60, Subpart OOOOb —Standards of Performance for Crude Oil and Natural Gas Facilities

Subpart OOOOb, Standards of Standards of Performance for Crude Oil and Natural Gas Facilities, applies to affected facilities that commenced construction, reconstruction, or modification after December 6, 2022. This renewal application does not involve the construction, reconstruction, or modification of any existing equipment. Therefore, Subpart OOOOb does not apply to any equipment at the facility.

2.3.7 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Affected sources under 40 CFR 60, Subpart IIII (NSPS IIII) include stationary compression ignition internal combustion engines that commence construction after July 11, 2005 and that were

manufactured after April 1, 2006, or that were manufactured as certified National Fire Protection Association (NFPA) fire pump engines after July 1, 2006.).

The 700 hp diesel-fired fire pump engines (S002, S003) and emergency engine(s) S058 with an aggregate hp rating of 3000 hp at NPP are subject to the requirements in NSPS IIII. The emergency generator (EG1) and fire pump (FP1) at the Natrium Power Plant are also subject to the standards and requirements of NSPS IIII.

2.3.8 40 CFR 60, Subpart KKKK —Standards of Performance for Stationary Combustion Turbines

The requirements of 40 CFR 60, Subpart KKKK (NSPS KKKK) apply to stationary combustion turbines constructed after February 18, 2005 rated at a heat input capacity of at least 10 MMBtu/hr. The Combined Cycle Combustion Turbines (CCCTs) at the Natrium Power Plant are subject to the emission limits and monitoring, recordkeeping, and reporting requirements of this section. The duct burners associated with the CCCTs are also subject to NSPS KKKK.

2.3.9 40 CFR 60, Subpart TTTT —Greenhouse Gas Emissions for Electric Utility Steam Generating Units

NSPS Subpart TTTT is applicable to an electric generating unit (EGU) with a base load rating greater than 250 MMBtu/hr that serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system and that commenced construction after January 8, 2014 (40 CFR 60.5509(a)).

Pursuant to 40 CFR 60.5509(b)(3), Blue Racer requested and was granted a federally enforceable permit limit that restricts the potential electric output to utility distribution systems for each of the combustion turbines to less than 219,000 MWh per year. As such, the requirements of this rule do not apply.

2.4 National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAPs), located in 40 CFR 63, are typically applicable to specific categories of sources that have the potential to emit hazardous air pollutants (HAP) in levels greater than 10 tpy for any individual HAP or 25 tpy for any combination of HAP (i.e., major HAP sources). Emissions and operational limitations provided in the NESHAPs are established on the basis of a Maximum Achievable Control Technology (MACT) determination for a particular major source category.

Furthermore, generally available control technology (GACT)-based NESHAPs (located in 40 CFR 63) require area (i.e., non-major) sources to control emissions to the level achievable by the use of generally available control technologies or management practices to reduce emissions of HAP.

Because the facility does not emit total or individual HAP in quantities greater than 25 and 10 tpy, respectively, the facility is considered an area (i.e., non-major) source of HAP. The following section of this report provides applicability determinations for each of the NESHAP standards to which the facility is potentially subject.

2.4.1 40 CFR 63, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities

Since the combined facility is an area source, potential applicability of Subpart HH is limited to the glycol dehydration unit (S006) at NPP. The actual average annual emissions of benzene from each glycol dehydration unit are less than 0.90 megagram per year (1.0 ton/year), therefore, S006 is exempt from 40 CFR 63, Subpart HH pursuant to 40 CFR 63.764(e)(1)(ii).

2.4.2 40 CFR 63, Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers

The standards of 40 CFR 63, Subpart JJJJJJ (Boiler GACT) apply to industrial boilers located at area sources; however, gas-fired units are not subject to the requirements of the Boiler GACT. All of the boilers, heaters, and duct burners at the Natrium Power Plant and NPP are gas-fired and are therefore exempt from these standards.

2.4.3 40 CFR 63, Subpart UUUUUU – Coal and Oil-fired Electric Utility Steam Generating Units

The standards of 40 CFR 63, Subpart UUUUU (the Utility Mercury Air Toxics Standard [Utility MATS]) apply to coal or oil-fired electric utility steam generating units. The turbines at the Natrium Power Plant are not subject to the standards of the Utility MATS given that these units will fire only natural gas.

2.4.4 40 CFR 63, Subpart YYYY – Stationary Combustion Turbines

The standards of 40 CFR 63, Subpart YYYY (MACT YYYY) apply to stationary combustion turbines located at major sources of HAP. Since the facility is classified as an area source, the facility is not subject to this standard.

2.4.5 40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)

According to 40 CFR 63.6590(a)(2)(iii), affected sources under 40 CFR 63, Subpart ZZZZ (MACT ZZZZ), include new stationary reciprocating internal combustion engines (RICE) installed at area sources after June 12, 2006; therefore, the emergency engines (S002, S003, S058, EG1, and FP1) are subject to the standards of MACT ZZZZ. As described in 40 CFR 63.6590(c)(1), new RICE located at area sources must comply with MACT ZZZZ by complying with the applicable requirements of NSPS IIII for compression ignition engines, and no further requirements under MACT ZZZZ apply to such engines. The diesel-fired emergency engines will comply with all applicable requirements under NSPS IIII, as discussed above.

2.5 Cross State Air Pollution Rule

Pursuant to 40 CFR 97.4(a)(1)(ii)(C), a cogeneration unit that meets the "unaffected unit" criteria in 40 CFR 72.6(b)(4) is not subject to the provisions of CSAPR.

40 CFR 72.6(b)(4)(ii) defines an unaffected cogeneration facility as follows:

A unit that commenced construction after November 15, 1990, and supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis).

Blue Racer requested and was granted a federally enforceable permit limit that restricts the potential electric output to utility distribution systems for each of the combustion turbines to less than 219,000 MWh per year. As such, the requirements of this rule do not apply.

2.6 Acid Rain Regulations

Pursuant to 40 CFR 75.2(b)(2), a unit that meets the criteria in 40 CFR 72.6(b), is not subject to the Acid Rain Program. As described in Section 3.1.5. (CSAPR), Blue Racer requested and was granted a federally enforceable permit limit that restricts the potential electric output to utility distribution systems for each of the combustion turbines to less than 219,000 MWh per year. As such, the requirements of this rule do not apply.

2.7 Compliance Assurance Monitoring

Under the CAM provisions of 40 CFR 64, facilities are required to prepare and submit monitoring plans for certain emission units with the application for the first renewal of the Title V Operating Permit. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-controlled emission levels exceed the major source thresholds under the Title V permitting program.

Blue Racer has conducted an evaluation of the uncontrolled emissions from sources at NPP and the Natrium Power Plant and has included the CAM applicability analysis in Appendix B.

2.8 Chemical Accident Prevention

Risk Management Plan (RMP) requirements are incorporated NPP's Title V operating permit per Condition 3.1.8. According to Condition 3.1.8,

Should this stationary source, as defined in 40 C.F.R. § 68.3, become subject to Part 68, then the owner or operator shall submit a risk management plan (RMP) by the date specified in 40 C.F.R. § 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 C.F.R. Part 70 or 71.
[40 C.F.R. 68]

The facility is subject to the RMP provisions. Per 40 CFR 68.190, sources subject to RMP provisions are required to update and resubmit RMPs at least every 5 years following the initial submittal. The facility is in compliance with all requirements of 40 CFR 68.

2.9 Stratospheric Ozone Protection Regulations

The requirements provided in Title VI of the Clean Air Act, entitled Protection of Stratospheric Ozone, are contained in 40 CFR 82. Because Blue Racer maintains, services, or disposes appliances utilizing refrigerants, 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, applies to such activities at the facility. Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified and follow specific work practices during repair, service, and disposal activities. All repairs, service, and disposal of ozone depleting substances from any chillers and air conditioners at the facility are completed by a certified technician.

2.10 West Virginia SIP Regulations

This section of the renewal application identifies specific West Virginia SIP regulations relevant to the facility.

2.10.1 45CSR2 – To Prevent and Control Particulate Matter Air Pollution From Combustion of Fuel in Indirect Heat Exchangers

This rule contains requirements for particulate matter emissions from the combustion of fuel in indirect heat exchangers. The hot oil heaters (S001, S016-S019, S052-S053) and the cryogenic HMO/stabilizer heaters (S013, S026, S037, S041, S045, S049, S056) are defined as fuel burning units and are subject to 45CSR2. The heaters are subject to an opacity limit, weight emission standards, Method 9 observations, any testing the director may deem appropriate, and recordkeeping requirements. According to 45CSR2-8.4.2, the heaters are exempt from 45CSR 2-8.1.1 and 8.2's testing and monitoring requirements since the units only combust natural gas.

The regeneration gas heaters (S012, S024, S036, S040, S044, S048) are not subject to 45CSR2 because they are defined as process heaters which are excluded from applicability.

At the Natrium Power Plant, the duct burners are subject to the emission limits and opacity restrictions of this rule. The Fuel Gas Heaters (FH1, FH2) are each rated at a capacity less than 10 MMBtu/hr and are therefore subject only to the opacity restriction. The turbines and engines do not operate by way of indirect heat transfer and are exempt from this rule.

2.10.2 45CSR6 – To Prevent and Control Air Pollution from Combustion of Refuse

The provisions of 45CSR6 include emissions standards for particulate and opacity generated in incineration units. NPP's ground flare (S004A) is subject to the requirements of this rule.

2.10.3 45CSR10 – To Prevent and Control Air Pollution from the Emission of Sulfur Oxides

This rule prevents and controls emissions of sulfur oxides (SO_X) from fuel burning sources, manufacturing process sources, and the combustion of refinery and/or process gas streams. The hot oil heaters (S001, S016-S019, S052-S053) and the cryogenic HMO/stabilizer heaters (S013, S026, S037, S041, S045, S049, S056) are subject to the SO_2 weight emission limit in 45CSR10-3.1.5 but are not subject to the testing and monitoring, recordkeeping, and reporting requirements under 45CSR10-8 and 45CSR10A since the units combust only natural gas.

The Combined Cycle Combustion Turbines and the duct burners at the Natrium Power Plant are subject to the emission limits established in this rule for Priority I Regions. The Fuel Gas Heaters (FH1, FH2) are each rated at a capacity less than 10 MMBtu/hr and are therefore exempt from this rule.

2.10.4 45CSR13 – Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation

This rule is generally applicable to NPP and the Natrium Power Plant. Currently, NPP Plant has one construction permit, R13-2896K, and the Natrium Power Plant has one construction permit, R13-3493.

2.10.5 45CSR16 – Standards of Performance for New Stationary Sources

45CSR16 incorporates by reference the federally promulgated NSPS. Refer to Section 2.3 of this report for a discussion of NSPS applicability.

2.10.6 45CSR22 – Air Quality Management Fee Program

This rule is generally applicable. In addition to permit to construct fees, 45CSR22-4.1a requires NPP to obtain a certificate to operate, which NPP obtains annually upon submittal of Certified Emission Statement.

2.10.7 45CSR40 – Control of Ozone Season Nitrogen Oxide Emissions

Pursuant to 45 CSR 40-4.1, units rated at heat inputs greater than 250 MMBtu/hr that are not subject to 40 CFR 97 are subject to the requirements of this rule.

40 CSR 45-5.1 requires that a NO_X emission rate must be established for each unit under a 45CSR13 permit.

40 CSR 40-6.1 requires a certified continuous emission monitoring system to attribute ozone season NO_X mass emissions to each unit in accordance with 40 CFR 75, Subpart H.

Blue Racer requested and was granted an hourly emission limit of 7.0 lb/hr during the ozone season. Blue Racer will comply with all applicable monitoring, recordkeeping, and reporting requirements set forth in 45CSR40.

2.10.8 45CSR34 – Emission Standards for Hazardous Air Pollutants

The provisions of 45CSR34 incorporate by reference the MACT standards contained in 40 CFR 63. Refer to Section 2.4 of this report for a discussion of MACT/GACT applicability.

3. WVDAQ APPLICATION FOR A TITLE V OPERATING PERMIT RENEWAL

West Virginia Department of Environmental Protection, Division of Air Quality, application for a renewal of a Title V Operating Permit.

The permit application forms in Attachments A through H and the supplemental information provided in Appendices A and B are being submitted as required by WVDEP for this Title V Operating Permit renewal application.

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY
601 57th Street SE
Charleston, WV 25304
Phone: (304) 926-0475
www.dep.wv.gov/daq

INITIAL/RENEWAL TITLE V PERMIT APPLICATION - GENERAL FORMS

Section 1: General Information

1. **Name of Applicant (As registered with the WV Secretary of State's Office):**
Blue Racer Midstream, LLC

2. Facility Name or Location:
Natrium Extraction and Fractionation Processing Plant (NNP)

3. DAQ Plant ID No.:
051-00142

4. Federal Employer ID No. (FEIN):
46-1520107

5. **Permit Application Type:**

☐ Initial Permit — When did operations commence?
☑ Permit Renewal — What is the expiration date of the existing permit? 4/14/2025
☐ Update to Initial/Renewal Permit Application

6. Type of Business Entity:

☐ Corporation ☐ Governmental Agency ☑ LLC
☐ Partnership ☐ Limited Partnership

7. Is the Applicant the:

☐ Owner ☐ Operator ☑ Both

If the Applicant is not both the owner and operator, please provide the name and address of the other party.

8. Number of onsite employees:
75

9. Governmental Code:

☑ Privately owned and operated; 0
☐ Federally owned and operated; 1
☐ State government owned and operated; 2
☐ County government owned and operated; 3
☐ Municipality government owned and operated; 4
☐ District government owned and operated; 5

10. Business Confidentiality Claims

Does this application include confidential information (per 45CSR31)? ☐ Yes ☑ No

If yes, identify each segment of information on each page that is submitted as confidential, and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's *"PRECAUTIONARY NOTICE-CLAIMS OF CONFIDENTIALITY"* guidance.

11. Mailing Address		
Street or P.O. Box: 14786 Energy Road		
City: Proctor	**State:** WV	**Zip:** 26055
Telephone Number:	**Fax Number:**	

12. Facility Location (Physical Address)		
Street: 14786 Energy Road	**City:** Proctor	**County:** Marshall
UTM Easting: 512.1 km	**UTM Northing:** 4,400.8 km	**Zone:** ☑ 17 or ☐ 18
Directions: Facility is located North of New Martinsville, WV off of State Route 2 at 14786 Energy Road, Proctor, WV 26055		
Portable Source? ☐ Yes ☑ No		
Is facility located within a nonattainment area? ☐ Yes ☑ No		**If yes, for what air pollutants?**
Is facility located within 50 miles of another state? ☑ Yes ☐ No		**If yes, name the affected state(s).** Ohio, Pennsylvania
Is facility located within 100 km of a Class I Area[1]? ☐ Yes ☑ No **If no, do emissions impact a Class I Area[1]?** ☐ Yes ☑ No		**If yes, name the area(s).**

[1] *Class I areas include Dolly Sods and Otter Creek Wilderness Areas in West Virginia, and Shenandoah National Park and James River Face Wilderness Area in Virginia.*

13. Contact Information		
Responsible Official: TJ Rinke		**Title:** Vice President
Street or P.O. Box: One Williams Center		
City: Tulsa	**State:** Oklahoma	**Zip:** 74172
Telephone Number: 918-573-9968	**Cell Number:** 918-240-4117	
E-mail address: t.j.rinke@williams.com		
Environmental Contact: Chris Hortert		**Title:** Environmental Specialist
Street or P.O. Box: 14786 Energy Road		
City: Proctor	**State:** WV	**Zip:** 26055
Telephone Number: 412-452-1893	**Cell Number:**	
E-mail address: chris.hortert@williams.com		
Application Preparer: DJ Wheeler		**Title:** Managing Consultant
Company: Trinity Consultants		
Street or P.O. Box: 440 Polaris Parkway, Suite 275		
City: Columbus	**State:** OH	**Zip:** 43082
Telephone Number: 614-568-8851	**Cell Number:** 231-670-3072	
E-mail address: dwheeler@trinityconsultants.com		

14. Facility Description

List all processes, products, NAICS and SIC codes for normal operation, in order of priority. Also list any process, products, NAICS and SIC codes associated with any alternative operating scenarios if different from those listed for normal operation.

Process	Products	NAICS	SIC
NG Extraction and Fractionation	Methane, Ethane, Propane, i-Butane, n-Butane, Natural Gas Condensate Liquids	211130	
Combined Cycle Electric Generation	Internal and External Electricity	221112	

Provide a general description of operations.

Muliple extraction trains operate with inlet and outlet electrical compression to remove Ethane, Propane, i-Butane, n-Butane and Condensate Liquids.

15. Provide an **Area Map** showing plant location as **ATTACHMENT A**.

16. Provide a **Plot Plan(s)**, e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is located as **ATTACHMENT B**. For instructions, refer to "Plot Plan - Guidelines."

17. Provide a detailed **Process Flow Diagram(s)** showing each process or emissions unit as **ATTACHMENT C**. Process Flow Diagrams should show all emission units, control equipment, emission points, and their relationships.

Section 2: Applicable Requirements

18. Applicable Requirements Summary	
Instructions: Mark all applicable requirements.	
☐ SIP	☐ FIP
☑ Minor source NSR (45CSR13)	☐ PSD (45CSR14)
☑ NESHAP (45CSR34)	☐ Nonattainment NSR (45CSR19)
☑ Section 111 NSPS	☐ Section 112(d) MACT standards
☐ Section 112(g) Case-by-case MACT	☑ 112(r) RMP
☐ Section 112(i) Early reduction of HAP	☐ Consumer/commercial prod. reqts., section 183(e)
☐ Section 129 Standards/Reqts.	☐ Stratospheric ozone (Title VI)
☐ Tank vessel reqt., section 183(f)	☐ Emissions cap 45CSR§30-2.6.1
☐ NAAQS, increments or visibility (temp. sources)	☐ 45CSR27 State enforceable only rule
☑ 45CSR4 State enforceable only rule	☐ Acid Rain (Title IV, 45CSR33)
☐ Emissions Trading and Banking (45CSR28)	☐ **C**ompliance **A**ssurance **M**onitoring (40CFR64)
☐ Cross-State Air Pollution Rule (45CSR43)	

19. Non Applicability Determinations

List all requirements which the source has determined not applicable and for which a permit shield is requested. The listing shall also include the rule citation and the reason why the shield applies.

45CSR19 – Requirements for Pre-Construction Review, Determination of Emission Offsets for Proposed New or Modified Stationary Sources of Air Pollutants and Emission Trading for Intrasource Pollutants; The facility-wide post-modification SO2 PTE of the plant is less than 100 TPY. Therefore the facility is not defined as a "major stationary source" under 45CSR19.
45CSR27 – To Prevent and Control the Emissions of Toxic Air Pollutants: Natural gas is included as a petroleum product and contains less than 5% benzene by weight. 45CSR§27-2.4 exempts equipment "used in the production and distribution of petroleum products providing that such equipment does not produce or contact materials containing more than 5% benzene by weight."
40 C.F.R. 63 Subpart HH; National Emission Standards for Hazardous Air Pollutants for Oil and Natural Gas Production Facilities: The facility would not be subject to the equipment leak standards under 40CFR§63.769 because it is an area source of HAPs, which limits applicability under Subpart HH to the (TEG) dehydration unit only according to 63.760(b)(2) as follows:
b) The affected sources for major sources are listed in paragraph (b)(1) of this section and for area sources in paragraph (b)(2) of this section.
For area sources, the affected source includes each triethylene glycol (TEG) dehydration unit located at a facility that meets the criteria specified in paragraph (a) of this section.

☑ Permit Shield

19. Non Applicability Determinations *(Continued)* - *Attach additional pages as necessary.*

List all requirements which the source has determined not applicable and for which a permit shield is requested. The listing shall also include the rule citation and the reason why the shield applies.

40 C.F.R. 63 Subpart DDDDD; National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters: This subpart does not apply to the facility since it is not a major source of HAPs as defined in 40CFR§63.7575.

40 C.F.R. 63 Subpart JJJJJJ; National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources: This subpart does not apply to the facility since the heaters are fueled by natural gas as defined in 40CFR§63.11195(e),

40 C.F.R. 60 Subpart TTTT; Blue Racer complies with a federally enforceable limit pursuant to 40 CFR 60.5509(b)(3) that restricts the potential electric output to utility distribution systems for each of the combustion turbines to less than 219,000 MWh per year. As such, the requirements of this rule do not apply.

40 C.F.R. 97; Blue Racer complies with a federally enforceable limit that restricts the potential electric output to utility distribution systems for each of the combustion turbines to less than 219,000 MWh per year. As such, the requirements of this rule do not apply.

40 C.F.R 75; Blue Racer complies with a federally enforceable limit that restricts the potential electric output to utility distribution systems for each of the combustion turbines to less than 219,000 MWh per year. As such, the requirements of this rule do not apply.

☑ Permit Shield

20. Facility-Wide Applicable Requirements

List all facility-wide applicable requirements. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*).

R13-2896K – 3.1.1 – 45 CSR 6-3.1 – Open burning prohibited
R13-2896K – 3.1.2 – 45 CSR 6-3.2 – Open burning exemption stipulations
R13-2896K – 3.1.3 – 40 CFR Part 61 and 45 CSR 34 – Asbestos inspection and removal
R13-2896K – 3.1.4 – 45 CSR 4 – No objectionable odors
R13-2896K – 3.1.5 – 45 CSR 13-10.5 – Permanent shutdown
R13-2896K – 3.1.6 – 45 CSR 11-5.2 – Standby plans for emergency episodes
WV Code 22-5-4 (a) (14) – Annual emission inventory reporting
40 CFR Part 82 Subpart F – Ozone depleting substances
40 CFR Part 68 – Risk Management Plan
45 CSR 30-12.7 – Emergency Operating Conditions / unit replacement
R13-2896K – 3.2.1 – Emission Limit Averaging Time
R13-2896K – 3.3.1 – 45 CSR 22-5-4(a)(14-15) & 45CSR13 - Stack Testing - Conduct stack testing as required
45 CSR 30-5.1 - Monitoring information – General monitoring requirements
R13-2896K – 3.4.1 – 45 CSR 30-5.1 – Retention of records- Maintain records for a period of 5 years
R13-2896K – 3.4.2 – 45 CSR 30-5.1 - Odors - Maintain records of odor complaints and corrective actions
R13-2896K – 3.5.1 – 45 CSR 30-4.4. and 5.1.c.3.D – Responsible Official
R13-2896K – 3.5.2 – 45 CSR 30-5.1.c.3.E. – Confidential Information
R13-2896K – 3.5.3 – 45 CSR 30-5 - Communication
45 CSR 30-8 – Certified Emissions Statement
45 CSR 30-5.3.e. - Compliance certification
45 SR§30-5.1.c.3.A - Semi-annual monitoring reports.
45 CSR 30-5.7.a through e. – Emergencies
45 CSR 30-5.1.c.3.B. and C. – Deviations
45 CSR 30-4.3.h.1.B – New applicable requirements

☑ Permit Shield

For all facility-wide applicable requirements listed above, provide monitoring/testing / recordkeeping / reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number and/or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

R13-2896K – 3.1.3 – 40 CFR Part 61 and 45 CSR 34 – Prior to demolition/construction buildings will be inspected for asbestos and documented accordingly
R13-2896K – 3.1.4 – 45 CSR 4 – Permittee shall maintain records of all odor complaints received
R13-2896K – 3.1.5 – 45 CSR 13-10.5 – A source not operated at least 500 hours in one 12 month period within the prior five year time frame may be considered permanently shutdown
R13-2896K – 3.1.6 – 45 CSR 11 – Upon request by the Secretary, the permittee shall prepare a standby plan for reducing emissions
WV 22-5-4 – The permittee shall submit annual emission inventory reports
40 CFR Part 82 Subpart F – The permittee will prohibit maintenance, service, or repair of appliances containing ozone depleting substances without persons certified pursuant to 40 CFR 82.161
40 CFR Part 68 – Should the permittee become subject to 40 CFR Part 68, a RMP shall be submitted
45CSR§30-12.7 For emergency situations which interrupt the critical supply of natural gas to the public, and which pose a life threatening circumstance to the customer, the permittee is allowed to temporarily replace failed engine(s). Proper notice will be provided to the WVDAQ
R13-2896K – 3.2.1 – Unless otherwise specified, compliance with all annual limits shall be based on a 12 month rolling total
R13-2896K – 3.3.1 – 45 CSR 22-5-4 Stack Testing – All protocols and reports will be submitted to the WVDAQ
R13-2896K – 3.4.1 – 45 CSR 30-5.1 Retention of Records - Maintain records of all information required by permit for 5 yrs.
R13-2896K – 3.4.2 – 45 CSR 30-5.1 Odors - Maintain records of all odor complaints and responses.
R13-2896K – 3.5.1 – 45 CSR 30-4.4 and 5.1 Responsible Official - Reports, certifications, etc. shall contain a certification by the responsible official.
R13-2896K – 3.5.2 – 45 CSR 30-5.1.c.3.E. - A permittee may request confidential treatment
R13-2896K – 3.5.3 – 45 CSR 30-5 - Communication required or permitted to be made to the DEP and/or USEPA
45 CSR 30-8 - Operator will Submit a certified emissions statement and pay fees on an annual basis
45 CSR 30-5.3.e. - The permittee shall certify compliance with the conditions of this permit on the forms provided by the DAQ on an annual basis
45 CSR30-5.7.a through e. - For reporting emergency situations, refer to Section 2.17 of this permit
45 CSR 30-5.1.c.3.B. and C. – In addition to required monitoring reports, the permittee shall promptly submit supplemental reports and notices of deviations / include upset conditions, cause of deviation(s) and corrective actions.
45 CSR 30-4.3.h.1.B. – If any requirement is promulgated, the permittee will meet such requirements on a timely basis

Are you in compliance with all facility-wide applicable requirements? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

20. Facility-Wide Applicable Requirements *(Continued)* - *Attach additional pages as necessary.*

List all facility-wide applicable requirements. For each applicable requirement, include the rule citation and/or permit with the condition number.

☐ Permit Shield

For all facility-wide applicable requirements listed above, provide monitoring/testing/recordkeeping/ reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number and/or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

Are you in compliance with all facility-wide applicable requirements? ☐ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

21. Active Permits/Consent Orders		
Permit or Consent Order Number	Date of Issuance MM/DD/YYYY	List any Permit Determinations that Affect the Permit *(if any)*
R13-2896K	08/17/2023	
CO-R13,30-E-2018-10	01/22/2019	
R13-3493	12/15/2020	
R30-05100142-2020 (MM03)	04/14/2020	

22. Inactive Permits/Obsolete Permit Conditions		
Permit Number	Date of Issuance MM/DD/YYYY	Permit Condition Number

Section 3: Facility-Wide Emissions

23. Facility-Wide Emissions Summary [Tons per Year]	
Criteria Pollutants	Potential Emissions
Carbon Monoxide (CO)	293.86
Nitrogen Oxides (NO_X)	310.63
Lead (Pb)	
Particulate Matter ($PM_{2.5}$)[1]	110.59
Particulate Matter (PM_{10})[1]	121.11
Total Particulate Matter (TSP)	153.28
Sulfur Dioxide (SO_2)	33.47
Volatile Organic Compounds (VOC)	309.11
Hazardous Air Pollutants[2]	Potential Emissions
Benzene	0.63
Toluene	2.01
Ethylbenzene	0.28
Xylene	0.93
n-Hexane	1.44
Formaldehyde	6.36
Methanol	8.39
Total HAPs	20.66
Regulated Pollutants other than Criteria and HAP	Potential Emissions
CO2e	1,920.085

[1]$PM_{2.5}$ and PM_{10} are components of TSP.
[2]For HAPs that are also considered PM or VOCs, emissions should be included in both the HAPs section and the Criteria Pollutants section.

Section 4: Insignificant Activities

24. Insignificant Activities (Check all that apply)		
☑	1.	Air compressors and pneumatically operated equipment, including hand tools.
☑	2.	Air contaminant detectors or recorders, combustion controllers or shutoffs.
☑	3.	Any consumer product used in the same manner as in normal consumer use, provided the use results in a duration and frequency of exposure which are not greater than those experienced by consumer, and which may include, but not be limited to, personal use items; janitorial cleaning supplies, office supplies and supplies to maintain copying equipment.
☑	4.	Bathroom/toilet vent emissions.
☑	5.	Batteries and battery charging stations, except at battery manufacturing plants.
☑	6.	Bench-scale laboratory equipment used for physical or chemical analysis, but not lab fume hoods or vents. Many lab fume hoods or vents might qualify for treatment as insignificant (depending on the applicable SIP) or be grouped together for purposes of description.
☐	7.	Blacksmith forges.
☑	8.	Boiler water treatment operations, not including cooling towers.
☑	9.	Brazing, soldering or welding equipment used as an auxiliary to the principal equipment at the source.
☐	10.	CO_2 lasers, used only on metals and other materials which do not emit HAP in the process.
☑	11.	Combustion emissions from propulsion of mobile sources, except for vessel emissions from Outer Continental Shelf sources.
☑	12.	Combustion units designed and used exclusively for comfort heating that use liquid petroleum gas or natural gas as fuel.
☑	13.	Comfort air conditioning or ventilation systems not used to remove air contaminants generated by or released from specific units of equipment.
☑	14.	Demineralized water tanks and demineralizer vents.
☐	15.	Drop hammers or hydraulic presses for forging or metalworking.
☐	16.	Electric or steam-heated drying ovens and autoclaves, but not the emissions from the articles or substances being processed in the ovens or autoclaves or the boilers delivering the steam.
☐	17.	Emergency (backup) electrical generators at residential locations.
☑	18.	Emergency road flares.

☒ 19. Emission units which do not have any applicable requirements and which emit criteria pollutants (CO, NO_x, SO_2, VOC and PM) into the atmosphere at a rate of less than 1 pound per hour and less than 10,000 pounds per year aggregate total for each criteria pollutant from all emission units.

Please specify all emission units for which this exemption applies along with the quantity of criteria pollutants emitted on an hourly and annual basis:

US-800	Spherical Storage Tank US-800	Pressurized. No emissions other than fugitive components.
US-801	Spherical Storage Tank US-801	Pressurized. No emissions other than fugitive components.
US-804	Spherical Storage Tank US-804	Pressurized. No emissions other than fugitive components.
US-805	Spherical Storage Tank US-805	Pressurized. No emissions other than fugitive components.
V-1905	Pressurized Bullet Tank V-1905	Pressurized. No emissions other than fugitive components.
V-1915	Pressurized Bullet Tank V-1915	Pressurized. No emissions other than fugitive components.
V-1925	Pressurized Bullet Tank V-1925	Pressurized. No emissions other than fugitive components.
V-1935	Pressurized Bullet Tank V-1935	Pressurized. No emissions other than fugitive components.
TK-950	Firewater Tank	Tank does not store organic liquids.
TK-605	TEG Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2605	TEG Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-119A	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-119B	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-840	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-810	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-850	Used Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2436	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
UT-909	Open Drain Sump (Oil/Water)	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK2119A	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK2119B	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
UK-2520	Amine Sump	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2524	Amine Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2522	Treated Water Storage Tank	Tank does not store organic liquids.
UT-607	Glycol Sump (TEG/Water)	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
FH1	Fuel Gas Heater #1	See Appendix A for detailed emissions calculations.

FH2	Fuel Gas Heater #2	See Appendix A for detailed emissions calculations.
OT1	Lubricating Oil Tank #1	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT2	Lubricating Oil Tank #2	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT3	Lubricating Oil Tank #3	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT4	Lubricating Oil Tank #4	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT5	Waste Oil Tank #1	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT6	Waste Oil Tank #2	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT7	Waste Oil Tank #3	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
OT8	Waste Oil Tank #4	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
FT1	Generator Fuel Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
FT2	Fire Pump Fuel Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
WS1	Washout Sump #1	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
WS2	Washout Sump #2	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
WS3	Washout Sump #3	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
WS4	Washout Sump #4	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
GT1	Glycol Tank #1	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
GT2	Glycol Tank #2	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
GT3	Glycol Tank #3	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
GT4	Glycol Tank #4	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
AT1	Ammonia Tank	Ammonia is not a regulated air pollutant.

24. Insignificant Activities (Check all that apply)		
☐	20.	Emission units which do not have any applicable requirements and which emit hazardous air pollutants into the atmosphere at a rate of less than 0.1 pounds per hour and less than 1,000 pounds per year aggregate total for all HAPs from all emission sources. This limitation cannot be used for any source which emits dioxin/furans nor for toxic air pollutants as per 45CSR27. Please specify all emission units for which this exemption applies along with the quantity of hazardous air pollutants emitted on an hourly and annual basis:
☐	21.	Environmental chambers not using hazardous air pollutant (HAP) gases.
☑	22.	Equipment on the premises of industrial and manufacturing operations used solely for the purpose of preparing food for human consumption.
☐	23.	Equipment used exclusively to slaughter animals, but not including other equipment at slaughterhouses, such as rendering cookers, boilers, heating plants, incinerators, and electrical power generating equipment.
☑	24.	Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.
☑	25.	Equipment used for surface coating, painting, dipping or spray operations, except those that will emit VOC or HAP.
☑	26.	Fire suppression systems.
☑	27.	Firefighting equipment and the equipment used to train firefighters.
☐	28.	Flares used solely to indicate danger to the public.
☑	29.	Fugitive emission related to movement of passenger vehicle provided the emissions are not counted for applicability purposes and any required fugitive dust control plan or its equivalent is submitted.
☐	30.	Hand-held applicator equipment for hot melt adhesives with no VOC in the adhesive formulation.
☑	31.	Hand-held equipment for buffing, polishing, cutting, drilling, sawing, grinding, turning or machining wood, metal or plastic.
☐	32.	Humidity chambers.
☑	33.	Hydraulic and hydrostatic testing equipment.
☐	34.	Indoor or outdoor kerosene heaters.
☑	35.	Internal combustion engines used for landscaping purposes.
☐	36.	Laser trimmers using dust collection to prevent fugitive emissions.
☐	37.	Laundry activities, except for dry-cleaning and steam boilers.
☑	38.	Natural gas pressure regulator vents, excluding venting at oil and gas production facilities.
☐	39.	Oxygen scavenging (de-aeration) of water.
☐	40.	Ozone generators.

24. Insignificant Activities (Check all that apply)		
☑	41.	Plant maintenance and upkeep activities (e.g., grounds-keeping, general repairs, cleaning, painting, welding, plumbing, re-tarring roofs, installing insulation, and paving parking lots) provided these activities are not conducted as part of a manufacturing process, are not related to the source's primary business activity, and not otherwise triggering a permit modification. (Cleaning and painting activities qualify if they are not subject to VOC or HAP control requirements. Asphalt batch plant owners/operators must still get a permit if otherwise requested.)
☑	42.	Portable electrical generators that can be moved by hand from one location to another. "Moved by Hand" means that it can be moved without the assistance of any motorized or non-motorized vehicle, conveyance, or device.
☑	43.	Process water filtration systems and demineralizers.
☑	44.	Repair or maintenance shop activities not related to the source's primary business activity, not including emissions from surface coating or de-greasing (solvent metal cleaning) activities, and not otherwise triggering a permit modification.
☑	45.	Repairs or maintenance where no structural repairs are made and where no new air pollutant emitting facilities are installed or modified.
☑	46.	Routing calibration and maintenance of laboratory equipment or other analytical instruments.
☐	47.	Salt baths using nonvolatile salts that do not result in emissions of any regulated air pollutants. Shock chambers.
☐	48.	Shock chambers.
☐	49.	Solar simulators.
☑	50.	Space heaters operating by direct heat transfer.
☐	51.	Steam cleaning operations.
☐	52.	Steam leaks.
☐	53.	Steam sterilizers.
☑	54.	Steam vents and safety relief valves.
☑	55.	Storage tanks, reservoirs, and pumping and handling equipment of any size containing soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.
☑	56.	Storage tanks, vessels, and containers holding or storing liquid substances that will not emit any VOC or HAP. Exemptions for storage tanks containing petroleum liquids or other volatile organic liquids should be based on size limits such as storage tank capacity and vapor pressure of liquids stored and are not appropriate for this list.
☐	57.	Such other sources or activities as the Director may determine.
☑	58.	Tobacco smoking rooms and areas.
☑	59.	Vents from continuous emissions monitors and other analyzers.

Section 5: Emission Units, Control Devices, and Emission Points

25. Equipment Table
Fill out the **Title V Equipment Table** and provide it as **ATTACHMENT D**.
26. Emission Units
For each emission unit listed in the **Title V Equipment Table**, fill out and provide an **Emission Unit Form** as **ATTACHMENT E**.
For each emission unit not in compliance with an applicable requirement, fill out a **Schedule of Compliance Form** as **ATTACHMENT F**.
27. Control Devices
For each control device listed in the **Title V Equipment Table**, fill out and provide an **Air Pollution Control Device Form** as **ATTACHMENT G**.
For any control device that is required on an emission unit in order to meet a standard or limitation for which the potential pre-control device emissions of an applicable regulated air pollutant is greater than or equal to the Title V Major Source Threshold Level, refer to the **Compliance Assurance Monitoring (CAM) Form(s)** for CAM applicability. Fill out and provide these forms, if applicable, for each Pollutant Specific Emission Unit (PSEU) as **ATTACHMENT H**.

Docusign Envelope ID: FF70D0B9-EFF1-4B01-8935-25F3925744CF

Section 6: Certification of Information

28. Certification of Truth, Accuracy and Completeness and Certification of Compliance

Note: This Certification must be signed by a responsible official as defined in 45CSR§30-2.38.

a. Certification of Truth, Accuracy and Completeness

I certify that I am a responsible official (as defined at 45CSR§30-2.38) and am accordingly authorized to make this submission on behalf of the owners or operators of the source described in this document and its attachments. I certify under penalty of law that I have personally examined and am familiar with the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine and/or imprisonment.

b. Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

Responsible official (type or print)

Name:	Title:
TJ Rinke	Vice President

Responsible official's signature:

Signature: DocuSigned by: TJ Rinke DE600755CD4A4F0... Signature Date: 8/19/2024

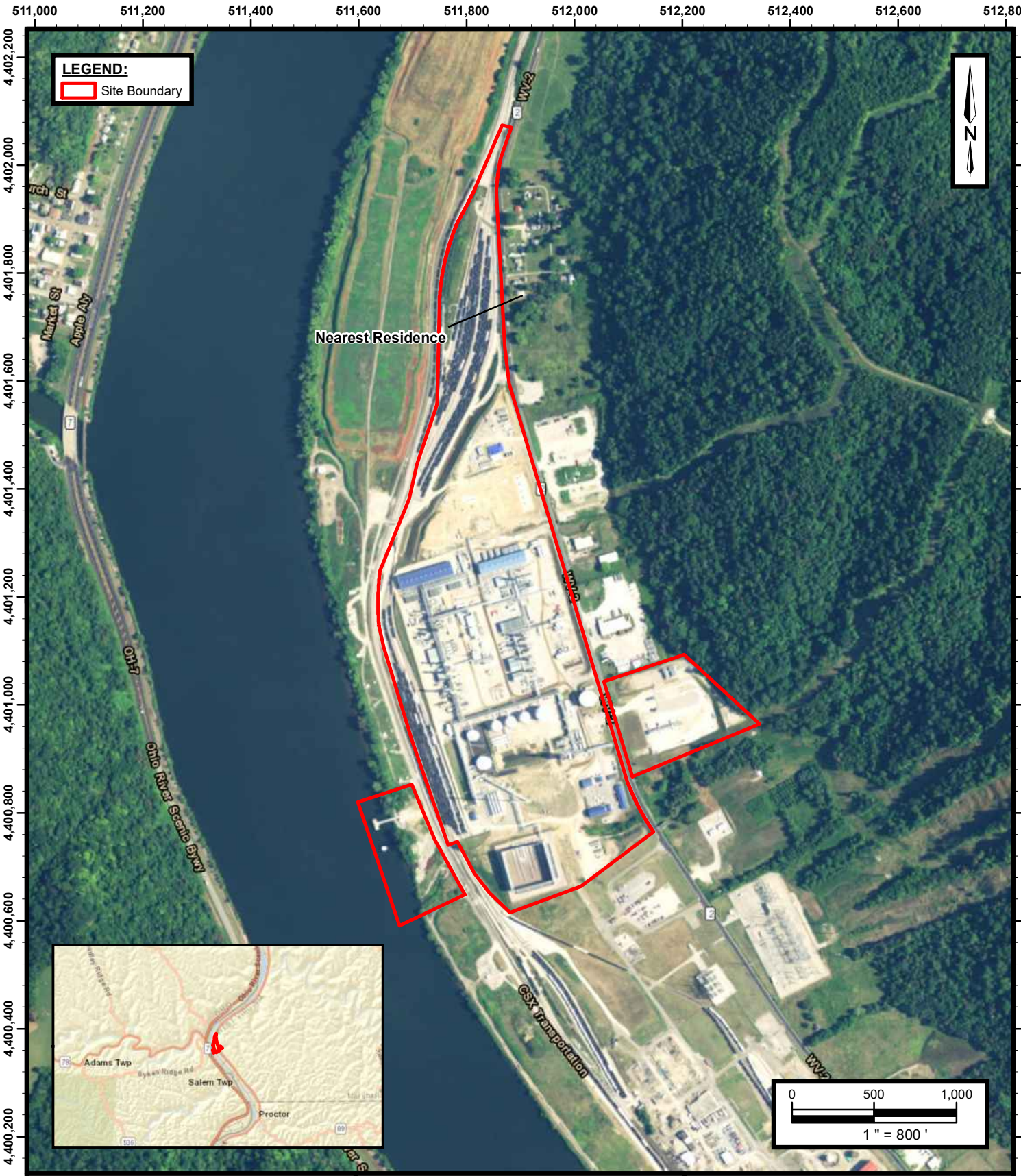
(Must be signed and dated in blue ink or have a valid electronic signature)

Note: Please check all applicable attachments included with this permit application:

☑	ATTACHMENT A: Area Map
☑	ATTACHMENT B: Plot Plan(s)
☑	ATTACHMENT C: Process Flow Diagram(s)
☑	ATTACHMENT D: Equipment Table
☑	ATTACHMENT E: Emission Unit Form(s)
☐	ATTACHMENT F: Schedule of Compliance Form(s)
☑	ATTACHMENT G: Air Pollution Control Device Form(s)
☑	ATTACHMENT H: Compliance Assurance Monitoring (CAM) Form(s)

All of the required forms and additional information can be found and downloaded from, the DEP website at www.dep.wv.gov/daq, requested by phone (304) 926-0475, and/or obtained through the mail.

ATTACHMENT A: AREA MAP



Blue Racer Midstream, LLC
Natrium Extraction and Fractionation Processing Plant
January 2019
Proctor, Marshall County, WV

Project No. 725010646036

Apex TITAN, Inc.
12100 Ford Road, Suite 401
Dallas, Texas 75234
Phone: (469) 365-1100
www.apexcos.com
A Subsidiary of Apex Companies, LLC

ATTACHMENT B-1

Area Map

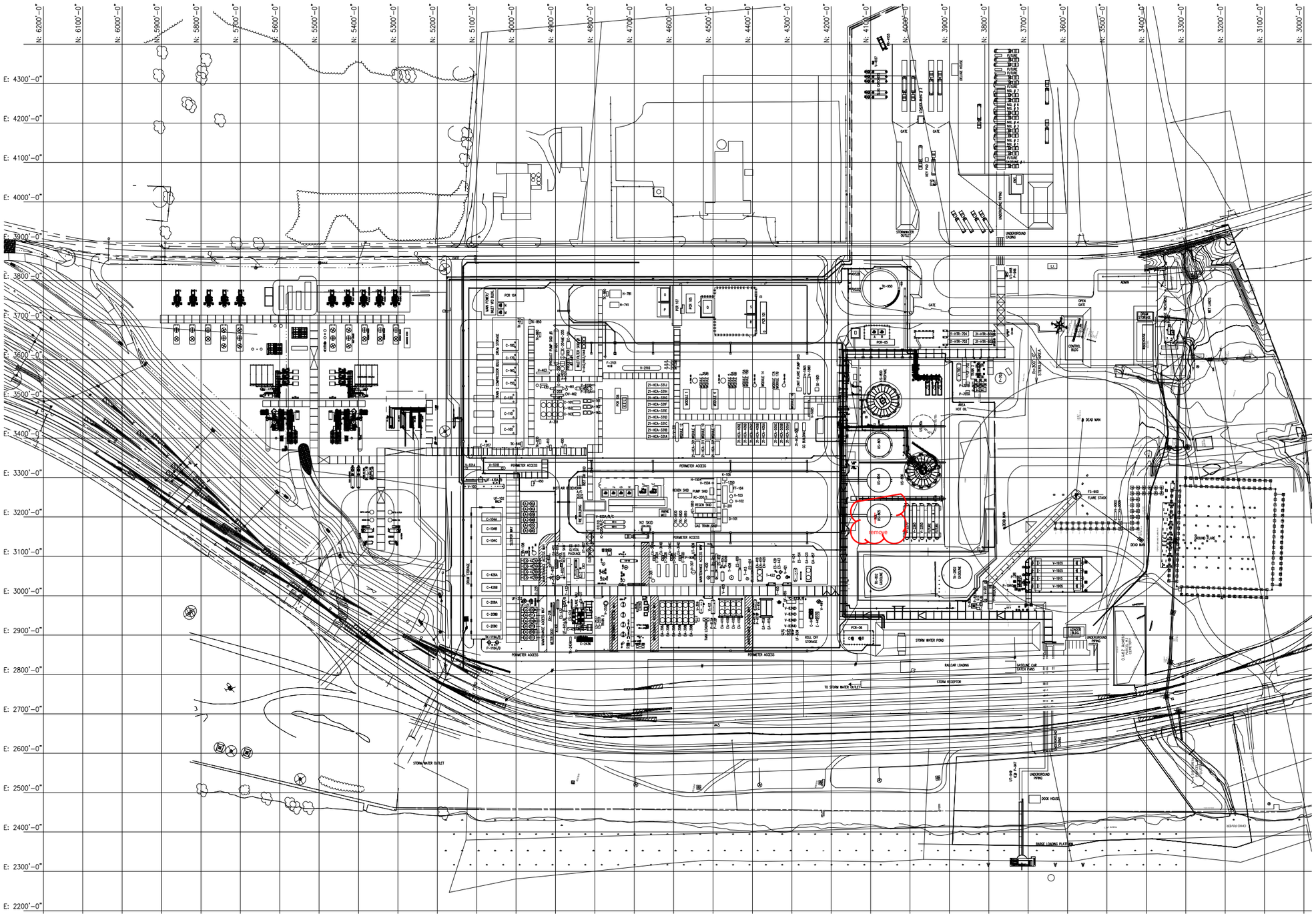
Service Layer Credits:
Sources: Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), MapmyIndia, NGCC, © OpenStreetMap contributors, and the GIS User Community
Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, Aerial Photograph July 2016

C:\Users\bmiller\OneDrive - Apex Companies, LLC\DT_Desktop\725010646035\Attachment B-1.mxd Modified 12/1/2017 by BMiller NAD 1983 UTM Zone 17N Coordinate System, Grid Listed in Meters

4/18/2019

ATTACHMENT B: PLOT PLAN

PLANT NORTH



NATRIUM FACILITY – PLOT PLAN
SCALE: 1/128"=1'–0"

NOTES:

1. LAYOUT SKETCH OF EXIST BRM NATRIUM FACILITY PRESENTED FOR REFERENCE PURPOSE ONLY. NO NEW DETAILED DESIGN DELIVERABLES ISSUED BY ZAP ECS AS PART OF WO# 62322–0002–222.62 ARE VISUALLY REPRESENTED IN THIS DWG.

ISSUED FOR REFERENCE

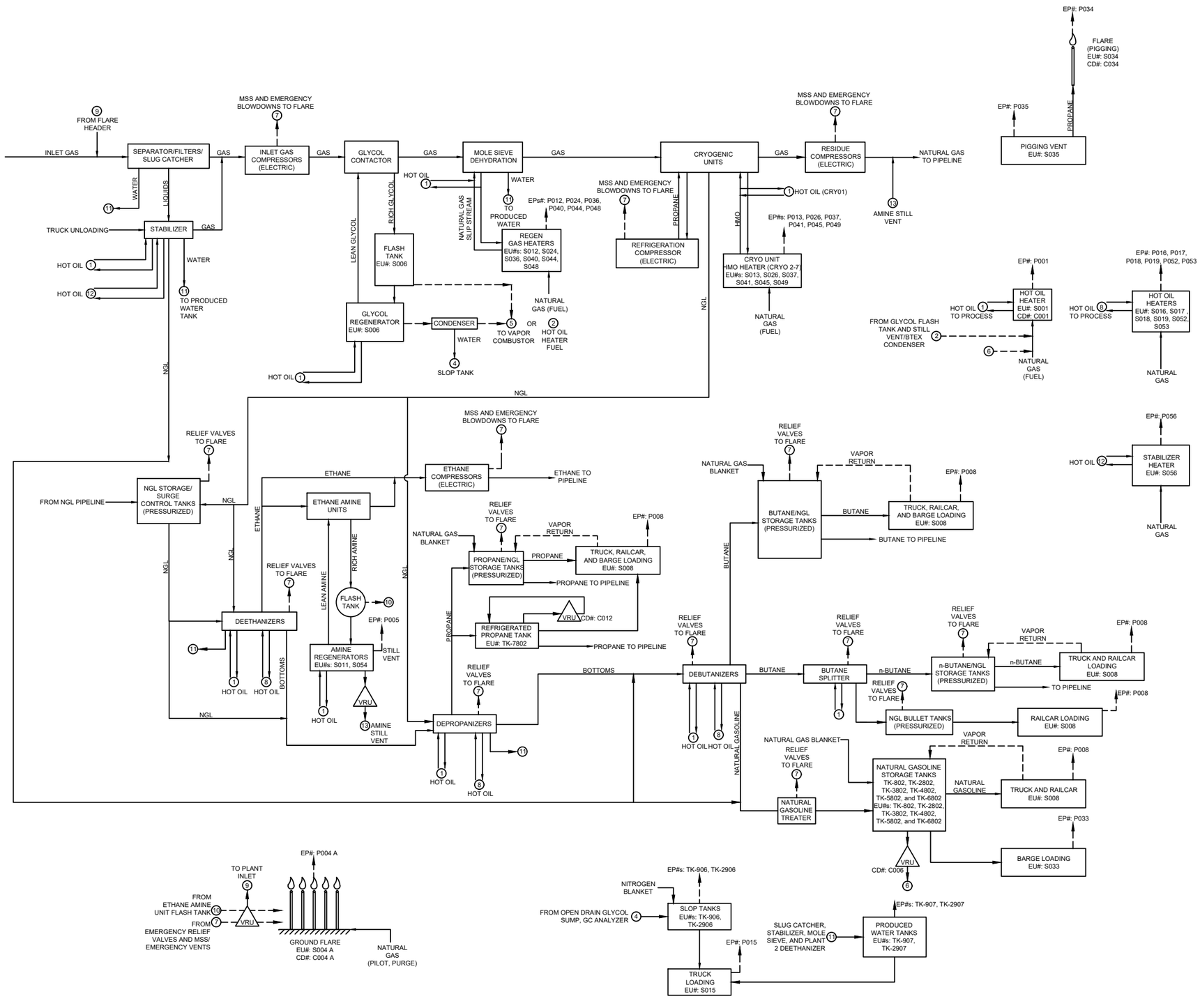
ZAP ENGINEERING & CONSTRUCTION SERVICES, INC.

REFERENCE DRAWINGS		No.	REVISION	BY	DATE	CHK.
NUMBER	TITLE	–	ISSUED FOR REFERENCE PER WO 62322–0002–222.62	PAS	11/10/23	
19078–G02–1001	ENLARGED PLOT PLAN					
21053–G02–1000	NATRIUM FIRE WATER OVERALL PLOT PLAN					

BLUE racer MIDSTREAM

LOCATION: NATRIUM FACILITY, PROCTOR, WEST VIRGINIA	SCALE: 1/128"=1'–0"	DRAWN BY: PAS	CHECKED BY:
FACILITY REFERENCE: Blue Racer – VRU Natrium Cryo 2			
DATE: 9/15/23	APPROVED: CWC	DRAWING NUMBER: 62322–0002–222.62_FACILITY REFERENCE	REV.: –
WO No.: 62322–0002–222.62			

ATTACHMENT C: PROCESS FLOW DIAGRAMS



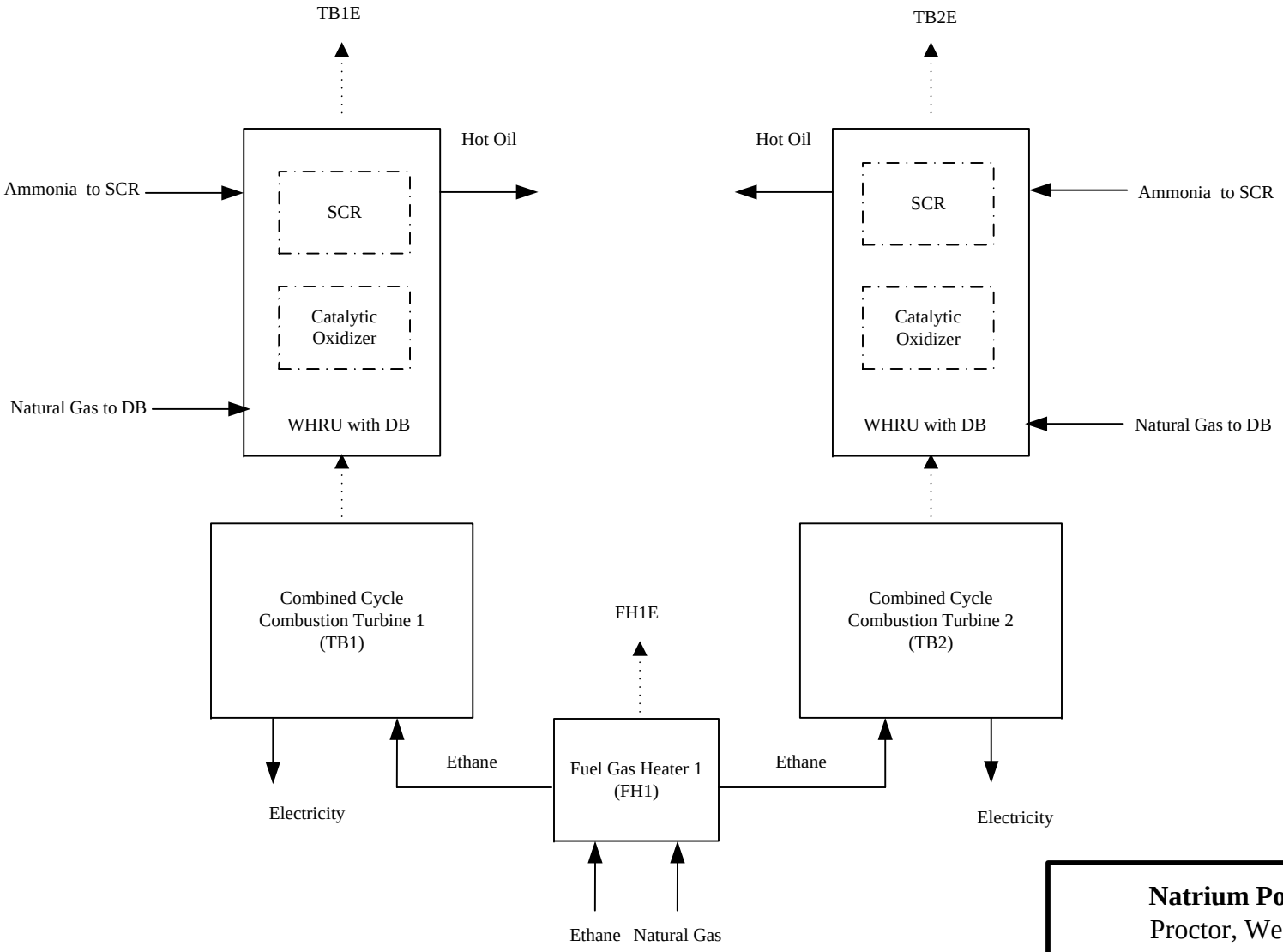
Blue Racer Midstream, LLC
Natrium Extraction and Fractionation Processing Plant

Proctor, Marshall County, WV

ATTACHMENT F

PROCESS FLOW DIAGRAM

Process Flow Diagram for TB1 and TB2



Legend

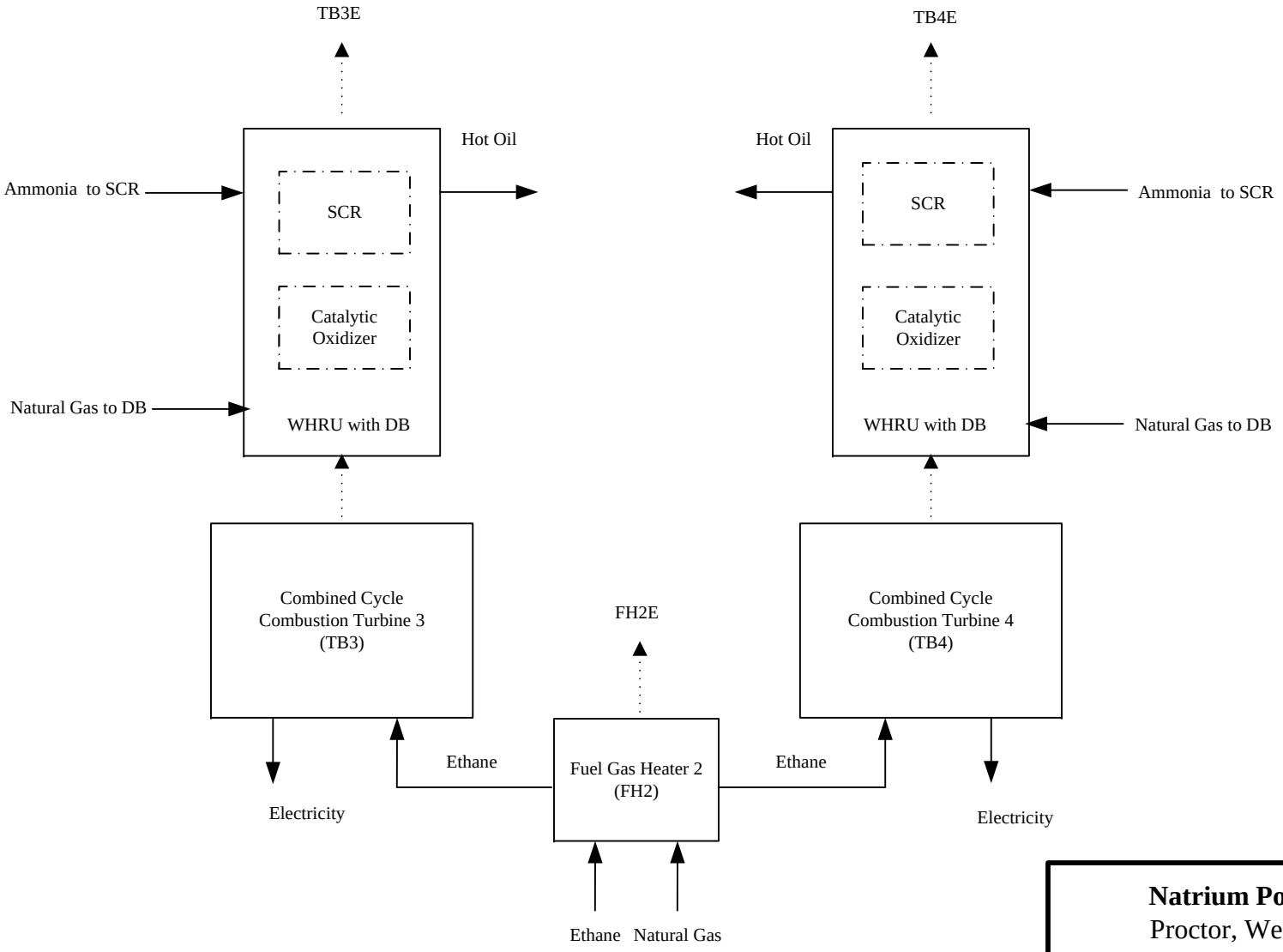
Material Flow

Air Emissions

Natrium Power Plant
Proctor, West Virginia

Process Flow Diagram

Process Flow Diagram for TB3 and TB4



Legend

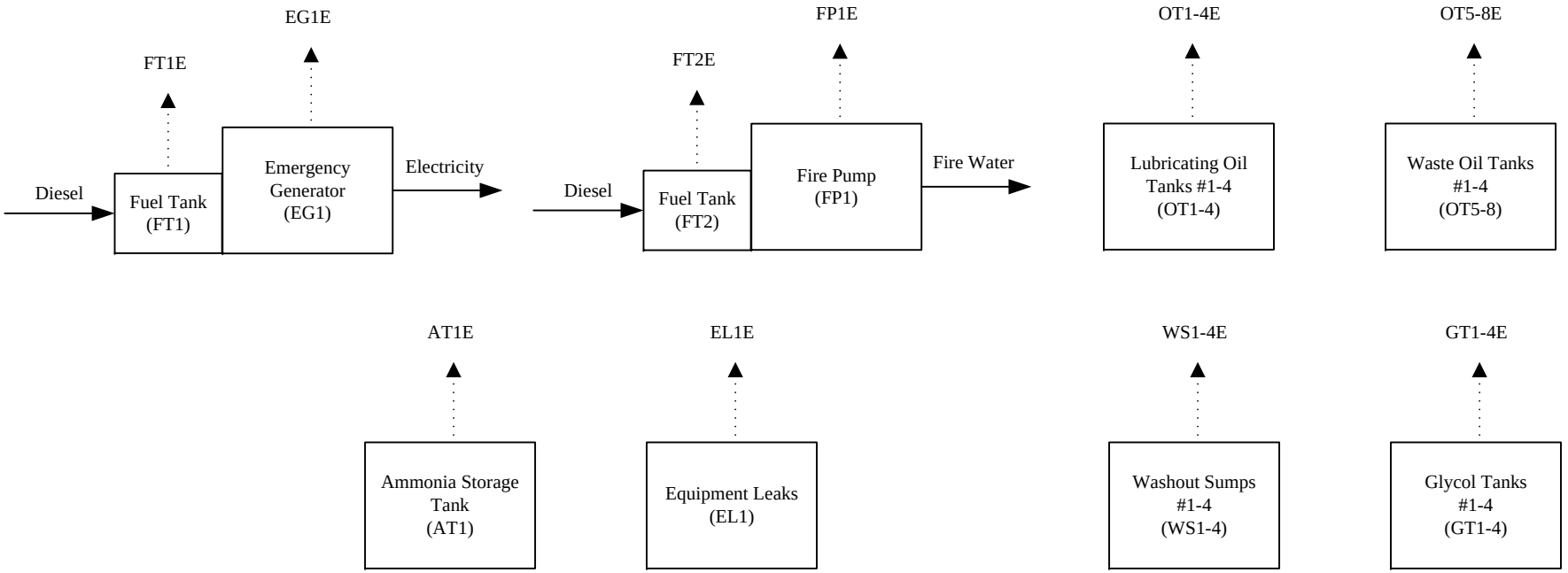
Material Flow

Air Emissions

Natrium Power Plant
Proctor, West Virginia

Process Flow Diagram

Process Flow Diagram for Ancillary Sources



Legend

Material Flow

Air Emissions

Natrium Power Plant
Proctor, West Virginia

Process Flow Diagram

ATTACHMENT D: EQUIPMENT TABLE

ATTACHMENT D - Title V Equipment Table

(includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)

Emission Unit ID[1]	Emission Point ID[1]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Control Device[1]
S001	P001	Hot Oil Heater (216.7 MMBtu/hr)	2018	216.7 MMBtu/hr	None
S002	P002	Fire Pump #1	2018	700 HP	None
S003	P003	Fire Pump #2	2018	700 HP	None
S004A	P004A	Ground Flare	2018	19,800,000 scf/hr	C004A
S006	P006	Glycol Dehydration Still Vent	2018	460 MMscfd	C001
S008	P008	Product Loading - Closed Loop	2011	35,000 gpm	Vapor Return to Tank
ROADS (S010)	ROADS	Unpaved Roads	2011	N/A	None
S011	P005	Ethane Amine Regenerator	2018	129 MMBtu/hr	None
S012	P012	Regen Gas Heater (9.7 MMBtu/hr)	2013	9.7 MMBtu/hr	None
S013	P013	Cryo HMO Heater (26.3 MMBtu/hr)	2013	26.3 MMBtu/hr	None
S015	P015	Slop Water Truck Loading	2018	N/A	None
S016	P016	Hot Oil Heater (61.6 MMBtu/hr)	2014	61.6 MMBtu/hr	None
S017	P017	Hot Oil Heater (61.6 MMBtu/hr)	2014	61.6 MMBtu/hr	None
S018	P018	Hot Oil Heater (61.6 MMBtu/hr)	2014	61.6 MMBtu/hr	None
S019	P019	Hot Oil Heater (61.6 MMBtu/hr)	2014	61.6 MMBtu/hr	None
S024	P024	Regen Gas Heater (9.7 MMBtu/hr)	2018	9.7 MMBtu/hr	None
S026	P026	Cryo HMO Heater (26.3 MMBtu/hr)	2018	26.3 MMBtu/hr	None
S033	P033	Barge Loading Vent	2017	N/A	None
S034	P034	Flare (Pigging)	2018	N/A	C034 Flare
S035	P035	Pigging Vent	2018	N/A	None
S036	P036	Regen Gas Heater (9.7 MMBtu/hr)	2019	9.7 MMBtu/hr	None
S037	P037	Cryo HMO Heater (26.3 MMBtu/hr)	2019	26.3 MMBtu/hr	None
S040	P040	Regen Gas Heater (19.28 MMBtu/hr)	2019	19.28 MMBtu/hr	None
S044	P044	Regen Gas Heater (9.7 MMBtu/hr)	2019	9.7 MMBtu/hr	None
S045	P045	Cryo HMO Heater (26.3 MMBtu/hr)	2019	26.3 MMBtu/hr	None

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

ATTACHMENT D - Title V Equipment Table

(includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)

Emission Unit ID[1]	Emission Point ID[1]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Control Device[1]
S048	P048	Regen Gas Heater (9.7 MMBtu/hr)	2019	9.7 MMBtu/hr	None
S049	P049	Cryo HMO Heater (26.3 MMBtu/hr)	2019	26.3 MMBtu/hr	None
S052	P052	Hot Oil Heater (61.6 MMBtu/hr)	2019	61.6 MMBtu/hr	None
S053	P053	Hot Oil Heater (61.6 MMBtu/hr)	2019	61.6 MMBtu/hr	None
S054	P054	Ethane Amine Regenerator	2019	129 MMscfd	C011
S055	P055	Pressurized NGL/Condensate	2012	N/A	N/A
S056	P056	Stabilizer Heater	2019	10.09 MMBtu/hr	N/A
S058	P058	Fire Pump Engine(s)	2023	3,000 hp	None
TK-802	P001	Natural Gasoline Storage Tank TK-802	2011	714,000 gallons	C001, C006
TK-2802	P001	Natural Gasoline Storage Tank TK-2802	2014	1,260,000 gallons	C001, C006
TK-3802	P001	Natural Gasoline Storage Tank TK-3802	2019	714,000 gallons	C001, C006
TK-4802	P001	Natural Gasoline Storage Tank TK-4802	2019	1,260,000 gallons	C001, C006
TK-5802	P001	Natural Gasoline Storage Tank TK-5802	2019	714,000 gallons	C001, C006
TK-6802	P001	Natural Gasoline Storage Tank TK-6802	2019	1,260,000 gallons	C001, C006
TK-7802	P001	Refrigerated Propane Storage Tank TK-7802	2019	4,200,000 gallons	C012
TK-906	TK-906	Slop Tank TK-906	2018	500 bbl	None
TK-907	TK-907	Produced Water Tank TK-907	2018	1,500 bbl	None
TK-2906	TK-2906	Slop Tank TK-2906	2019	500 bbl	None
TK-2907	TK-2907	Produced Water Tank TK-2907	2019	1,500 bbl	None
TK-L-1	TK-L-1	Gasoline Dispensing Tank	2017	1,000 gallons	None
L-1	L-1	Gasoline Dispensing Loading	2017	N/A	None
FUG AREA 1	FUG AREA 1	Fugitive Area 1 (Cryo 1 (Excluding Demethanizer) & Cryo 2)	2018	N/A	None
FUG AREA 2	FUG AREA 2	Fugitive Area 2 (Cryo 1 Demethanizer & Frac 2)	2014	N/A	None
FUG AREA 3	FUG AREA 3	Fugitive Area 3 (Cryo 3)	2018	N/A	None
FUG AREA 4	FUG AREA 4	Fugitive Area 4 (Cryo 4 & Frac 1)	2019	N/A	None

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

ATTACHMENT D - Title V Equipment Table

(includes all emission units at the facility except those designated as insignificant activities in Section 4, Item 24 of the General Forms)

Emission Unit ID[1]	Emission Point ID[1]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Control Device[1]
FUG AREA 5	FUG AREA 5	Fugitive Area 5 (Cryo 5)	2019	N/A	None
FUG AREA 6	FUG AREA 6	Fugitive Area 6 (Cryo 6)	2019	N/A	None
FUG AREA 7	FUG AREA 7	Fugitive Area 7 (Cryo 7)	2019	N/A	None
TB1A-4A	TB1AE-4AE	Turbine #1-4 - LM6000PG Sprint	TBD	482.6 MMBtu/hr	OC1-4, SCR1-4
TB1B-4B	TB1BE-4BE	Turbine #1-4 - SGT-800	TBD	496.2 MMBtu/hr	OC1-4, SCR1-4
TB1A/B-4A/B	TB1A/BE-4A/BE	Duct Burners #1-4	TBD	475.1 MMBtu/hr	OC1-4, SCR1-4
S041	P041	Cryo HMO Heater (54.67 MMBtu/hr)	2019	54.67 MMBtu/hr	None
EG1	EG1E	Emergency Generator	TBD	1,676 hp	None
FP1	FP1E	Emergency Fire Pump Engine	TBD	700 hp	None

[1]For 45CSR13 permitted sources, the numbering system used for the emission points, control devices, and emission units should be consistent with the numbering system used in the 45CSR13 permit. For grandfathered sources, the numbering system should be consistent with registrations or emissions inventory previously submitted to DAQ. For emission points, control devices, and emissions units which have not been previously labeled, use the following 45CSR13 numbering system: 1S, 2S, 3S,... or other appropriate description for emission units; 1C, 2C, 3C,... or other appropriate designation for control devices; 1E, 2E, 3E, ... or other appropriate designation for emission points.

ATTACHMENT E: EMISSION UNIT FORMS

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S001	Hot Oil Heater (216.7 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect Heat Exchanger

Manufacturer:	**Model number:**	**Serial number:**
Optimized Process Furnaces		
Construction date:	**Installation date:**	**Modification date(s):**
	2014	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

216.7 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
216.7 MMBtu/hr		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☑ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 216.7 MMBtu/hr	**Type and Btu/hr rating of burners:** 216.7 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
225,571 scf/hr
1,976 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100ft^3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.25	14.24
Nitrogen Oxides (NO_X)	9.75	42.71
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	1.61	7.07
Particulate Matter (PM_{10})	1.61	7.07
Total Particulate Matter (TSP)	1.61	7.07
Sulfur Dioxide (SO_2)	0.15	0.67
Volatile Organic Compounds (VOC)	0.37	1.61
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH20	5.02E-03	2.20E-02
N-Hexane	8.71E-05	3.81E-04
Benzene	1.41E-04	6.16E-04
Toluene	2.28E-04	9.97E-04
Other HAPs	1.30E-04	5.68E-04
Total HAPs	5.61E-03	2.46E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 - Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 216.7 mmBtu/hr = 19.5 lb/hr] However the unit is subject to a more stringent emission limit of 0.37 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.a.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1 and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 216.7 mmBtu/hr = 671.77 lb/hr] However the unit is subject to a more stringent emission limit of 0.15 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.a.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Db
40 C.F.R. § 60.40b(a) – Applicability

40 C.F.R. § 60.42b– SO_2 Emission Standards

40 C.F.R. § 60.44b – NOx Emission Standards

40 C.F.R. § 60.48b – Monitoring Requirements

40 C.F.R. § 60.49b – Reporting / Recordkeeping Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 216.7 mmBtu/hr.

Condition 5.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	9.75	42.71
CO	3.25	14.24
$PM_{2.5}$ / PM_{10} / PM(1)	1.61	7.07
SO_2	0.15	0.67
VOCs	0.37	1.61

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 225,571 scf/hr and 1,976 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/ hr, provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.1]**

Condition 5.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 5.1.5.a – Units firing only very low sulfur, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/mmBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section **[40CFR§60.42b(k)(2)]**

Condition 5.1.5.b – Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from the affected facility any gases that contain NOx (expressed as NO_2) in excess of the following emission limits; (1) Low heat release rate: 0.10 lb/mmBtu / (2) High heat release rate: 0.20 lb/mmBtu **[40CFR§60.44b(a)(1)(i) and (ii)]**

Condition 5.1.5.c – Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NOx standard under §60.44b shall comply with paragraph (b)(1) of this section; (1) install, calibrate, maintain and operate CEMS for measuring NOx and O_2 or (CO_2) emissions discharged to the atmosphere, and shall record the output of the system **[40CFR§60.48b(b)(1)]**

Condition 5.1.5.d – Pursuant §60.49b(r)(2)(iv), the WVDAQ approves quarterly fuel sampling for the unit

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Db
40 C.F.R. § 60.42b(k)(2) – Units firing only very low sulfur, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/mmBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) §60.42b.

40 C.F.R. § 60.44b(a)(1)(i) – Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from the affected facility any gases that contain NOx (expressed as NO_2) in excess of the following emission limits; (1) Low heat release rate: 0.10 lb/mmBtu

40 C.F.R. § 60.46b(e)(1) – Conduct initial performance test for NOx using the CEMS to collect thirty (30) days of data

40 C.F.R. § 60.48b(b)(1) – Install, calibrate, maintain and operate CEMS for measuring NOx and O_2 or (CO_2) emissions discharged to the atmosphere, and shall record the output of the system

40 C.F.R. § 60.48b(c) – CEMS shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero span

40 C.F.R. § 60.48b(d) – Record one hour average NOx measured by the CEMS in ng/j or lb/mmbtu heat input, and used to calculate the average emission rates under §60.44b. The one hour averages shall be calculated using the data points required under § 60.13(h)(2)

40 C.F.R. § 60.49b(a) – Owner/operator shall submit notification of the date of construction and startup

40 C.F.R. § 60.49b(b) – Owner/operator shall report performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specification in Appendix B of this part

40 C.F.R. § 60.49b(h)(2)(i) – Owner/operator is required to submit excess emission reports for any excess emissions that occurred during the reporting period

40 C.F.R. § 60.49b(r) – Owner/operator shall obtain and maintain fuel receipts from the fuel supplier that certify the oil meets the definition natural gas as defined in §60.41b or perform sampling of fuel gas in accordance with an Administrator approved site specific fuel analysis plan that includes sampling on a quarterly basis.

45 C.S.R. 13, Permit R13-2896K
Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S002	Fire Pump #1	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Diesel Fired Engine

Manufacturer:	**Model number:**	**Serial number:**
Caterpillar	C18	
Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp): 700 hp

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		100 hrs/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☒ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 700 hp	**Type and Btu/hr rating of burners:** 137,030 btu/gal

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel
35.9 gal/hr
3,590 gal/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100 ft^3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	4.01	0.20
Nitrogen Oxides (NO_X)	4.63	0.23
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.23	0.01
Particulate Matter (PM_{10})	0.23	0.01
Total Particulate Matter (TSP)	0.23	0.01
Sulfur Dioxide (SO_2)	0.01	0.0004
Volatile Organic Compounds (VOC)	4.63	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	3.88E-04	1.94E-05
Benzene	3.82E-03	1.91E-04
Toluene	1.38E-03	6.91E-05
Xylene	9.49E-04	4.75E-05
Total HAPS	7.74E-03	3.87E-04
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 3.4 – Large Stationary Diesel and All Stationary Dual-Fuel Engines

40 CFR 60 Subpart IIII, Table 4

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart IIII
40 C.F.R. § 60.4200(a)(2)(ii) – Applicability

40 C.F.R. § 60.4205(c), 60.4206, and Table 4 (Line 18) – Operating Requirements

40 C.F.R. § 60.4207(b) – Fuel Requirements

40 C.F.R. § 60.4209(a) – Monitoring Requirements

40 C.F.R. § 60. 4211(a), (c), (f) and (g) – Compliance Requirements

40 C.F.R. § 60.4214(b) – Recordkeeping Requirements

40 C.F.R. 63 Subpart ZZZZ
40 C.F.R. § 63.6590(c)(1) – General Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 8.1.1 – Quantity of diesel fuel consumed by the unit shall not exceed 35.9 gal/hr and 3,590 gal/year per rolling (12) moth period during non-emergency use.

Condition 8.1.2. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	4.63	0.23
CO	4.01	0.20
$PM_{2.5}$ / PM_{10} / PM(1)	0.23	0.01
VOCs	4.63	0.23

(1) Includes condensables

Condition 8.1.3 – Maximum yearly hours of operation for the unit shall not exceed an annual limit of 100 hrs of non-emergency use as recorded with a non-resettable hour meter. Compliance with the limitation shall be determined using a 12 month rolling total.

Condition 8.1.4. – Owner/Operators of fire pump engines with a displacement of less than 30 litres per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants. **[40CFR§60.4205(c)]**

Condition 8.1.5. – An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR Part 60 Subpart IIII. No further requirements apply for such engines under this part. **[40CFR§63.6590(c)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart IIII
40 C.F.R. § 60.4205(c), 60.4206, and Table 4 (Line 18) – Unit shall comply with the emission standards set forth for NMHC + NOx (3.0 g/hp-hr), CO (2.6 g/hp-hr) and PM (0.15 g/hp-hr) for the entire life of the engine.

40 C.F.R. § 60.4207(b) – Ensure diesel fuel used in unit meets the requirements of 40CFR 80.510(b) for nonroad diesel fuel.

40 C.F.R. § 60.4209(a) – Install a non-resettable meter to monitor hours of operation.

40 C.F.R. § 60.4211(c) – Comply with the emissions standards specified in § 60.4205(c) by purchasing an engine certified to the emission standards. The unit must be installed and configured according to the manufacturer's related specifications.

40 C.F.R. § 60.4211(f) – Compliance/Operation;

- There is no time limit to operation of unit during emergency situations
- Operation of unit shall be limited to a maximum of 100 hours per calendar year for any combination of maintenance & readiness testing, emergency demand response, periods of voltage or frequency deviations and select non-emergency operations.
- Non-emergency operations shall not exceed 50 hours per calendar year and are to be counted as part of the maximum 100 hours per calendar year operation limitation as described in the previous paragraph

40 C.F.R. § 60.4211(g) – Owner/operators that do not install, configure, operate, and maintain units according to the manufacturer's emission related written instructions, or if a change is made in a way that is not permitted by the manufacturer, compliance must be demonstrated by developing a maintenance plan and keeping records of maintenance conducted. In addition, an initial performance test shall be conducted to demonstrate compliance within one year of startup or within one year of the change made not permitted by the manufacturer. Subsequent testing shall be completed every 8,760 hours of operation or three years whichever comes first.

40 C.F.R. § 60.4214(b) – Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

40 C.F.R. 63 Subpart ZZZZ

40 C.F.R. 63.6590(c)(1) – Demonstrate compliance with this regulation by complying with the applicable parts of 40 CFR 60 Subpart IIII. No further requirements will apply under this subpart

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S003	Fire Pump #2	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Diesel Fired Engine

Manufacturer:	**Model number:**	**Serial number:**
Caterpillar	C18	
Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp): 700 hp

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		100 hrs/yr

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☒ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 700 hp	**Type and Btu/hr rating of burners:** 137,030 btu/gal

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel Fuel
35.9 gal/hr
3,590 gal/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100 ft^3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	4.01	0.20
Nitrogen Oxides (NO_X)	4.63	0.23
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.23	0.01
Particulate Matter (PM_{10})	0.23	0.01
Total Particulate Matter (TSP)	0.23	0.01
Sulfur Dioxide (SO_2)	0.01	0.0004
Volatile Organic Compounds (VOC)	4.63	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	3.88E-04	1.94E-05
Benzene	3.82E-03	1.91E-04
Toluene	1.38E-03	6.91E-05
Xylene	9.49E-04	4.75E-05
Total HAPS	7.74E-03	3.87E-04
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 3.4 – Large Stationary Diesel and All Stationary Dual-Fuel Engines

40 CFR 60 Subpart IIII, Table 4

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart IIII
40 C.F.R. § 60.4200(a)(2)(ii) – Applicability

40 C.F.R. § 60.4205(c), 60.4206, and Table 4 (Line 18) – Operating Requirements

40 C.F.R. § 60.4207(b) – Fuel Requirements

40 C.F.R. § 60.4209(a) – Monitoring Requirements

40 C.F.R. § 60. 4211(a), (c), (f) and (g) – Compliance Requirements

40 C.F.R. § 60.4214(b) – Recordkeeping Requirements

40 C.F.R. 63 Subpart ZZZZ
40 C.F.R. § 63.6590(c)(1) – General Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 8.1.1 – Quantity of diesel fuel consumed by the unit shall not exceed 35.9 gal/hr and 3,590 gal/year per rolling (12) moth period during non-emergency use.

Condition 8.1.2. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	4.63	0.23
CO	4.01	0.20
$PM_{2.5}$ / PM_{10} / PM(1)	0.23	0.01
VOCs	4.63	0.23

(1) Includes condensables

Condition 8.1.3 – Maximum yearly hours of operation for the unit shall not exceed an annual limit of 100 hrs of non-emergency use as recorded with a non-resettable hour meter. Compliance with the limitation shall be determined using a 12 month rolling total.

Condition 8.1.4. – Owner/Operators of fire pump engines with a displacement of less than 30 litres per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants. **[40CFR§60.4205(c)]**

Condition 8.1.5. – An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR Part 60 Subpart IIII. No further requirements apply for such engines under this part. **[40CFR§63.6590(c)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart IIII
40 C.F.R. § 60.4205(c), 60.4206, and Table 4 (Line 18) – Unit shall comply with the emission standards set forth for NMHC + NOx (3.0 g/hp-hr), CO (2.6 g/hp-hr) and PM (0.15 g/hp-hr) for the entire life of the engine.

40 C.F.R. § 60.4207(b) – Ensure diesel fuel used in unit meets the requirements of 40CFR 80.510(b) for nonroad diesel fuel.

40 C.F.R. § 60.4209(a) – Install a non-resettable meter to monitor hours of operation.

40 C.F.R. § 60.4211(c) – Comply with the emissions standards specified in § 60.4205(c) by purchasing an engine certified to the emission standards. The unit must be installed and configured according to the manufacturer's related specifications.

40 C.F.R. § 60.4211(f) – Compliance/Operation;

- There is no time limit to operation of unit during emergency situations
- Operation of unit shall be limited to a maximum of 100 hours per calendar year for any combination of maintenance & readiness testing, emergency demand response, periods of voltage or frequency deviations and select non-emergency operations.
- Non-emergency operations shall not exceed 50 hours per calendar year and are to be counted as part of the maximum 100 hours per calendar year operation limitation as described in the previous paragraph

40 C.F.R. § 60.4211(g) – Owner/operators that do not install, configure, operate, and maintain units according to the manufacturer's emission related written instructions, or if a change is made in a way that is not permitted by the manufacturer, compliance must be demonstrated by developing a maintenance plan and keeping records of maintenance conducted. In addition, an initial performance test shall be conducted to demonstrate compliance within one year of startup or within one year of the change made not permitted by the manufacturer. Subsequent testing shall be completed every 8,760 hours of operation or three years whichever comes first.

40 C.F.R. § 60.4214(b) – Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

40 C.F.R. 63 Subpart ZZZZ

40 C.F.R. 63.6590(c)(1) – Demonstrate compliance with this regulation by complying with the applicable parts of 40 CFR 60 Subpart IIII. No further requirements will apply under this subpart

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S004A	Ground Flare	C004A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Ground Flare

Manufacturer:	**Model number:**	**Serial number:**
Callidus	CAL-MP	
Construction date:	**Installation date:**	**Modification date(s):**
	2015	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

19,800,000 scf/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
NA		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☒ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 22,500 mmBtu/hr	**Type and Btu/hr rating of burners:** 22,500 mmBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
19,800,000 scf/hr
173,448 mmscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100 ft^3	N/A	1,136 btu/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3,073.64	29.17
Nitrogen Oxides (NO_X)	1,539.61	14.61
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	30.66	0.50
Particulate Matter (PM_{10})	30.66	0.50
Total Particulate Matter (TSP)	30.66	0.50
Sulfur Dioxide (SO_2)	0.001	0.005
Volatile Organic Compounds (VOC)	10,174.95	39.75
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Benzene	1.90E-03	8.50E-04
N-Hexane	4.53E+00	1.19E-01
Toluene	2.64E-03	1.18E-03
Xylene	9.37E-04	4.20E-04
Total HAPS	4.53E+00	1.21E-01
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

TNRCC Guidance Document for Flares and Vapor Oxidizers

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 6
45 C.S.R. 6-4.1 – Particulate Matter Emission Limitation; The total allowable emission rate of PM for the unit shall be calculated using the following equation; Emissions (lb/hr) = F x Incinerator Capacity (tons/hr) where the F factor has a value of 2.72 for incinerators with capacity of greater than 15,000 lbs/hr. The PM Emission Limit for this unit will be 1,136 lb/hr [2.72 x IC (417.6) ton/hr = 1,136 lb/hr].

45 C.S.R. 6-4.3 – Opacity Limitations; No person shall cause or allow emission of smoke into atmosphere from the unit which is 20% opacity or higher.

45 C.S.R. 6-4.4 – Opacity Limitations during Startup; The provisions of subsection 4.3 shall not apply to smoke which is less than 40% opacity, for a period or periods aggregating no more than eight (8) minutes per start up.

45 C.S.R. 6-4.5 – Refuse/Ash; No person shall cause, allow or permit the emission of particles of unburned or partially burned refuse or ash from the flare which are large enough to be individually distinguished in the open air.

45 C.S.R. 6-4.6 – Objectionable Odors; Flare shall be designed, operated, and maintained so as to prevent the emission of objectionable odors

45 C.S.R. 30-12.7
Flare shall be steam-assisted, air-assisted, or non-assisted.

Flare shall be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Flare shall be operated with a flame present at all times except during SSM.

Flare shall be designed to meet the Btu and exit velocity requirements in accordance with 63.11.

45 C.S.R. 13, Permit R13-2896K
Condition 13.1.1. – Permittee shall utilize a non-assisted Callidus CAL-MP staged, multi-point ground flare system (with a maximum aggregate pilot light heat input of 1.629 mmBtu/hr) for control of potential emissions from maintenance events, equipment blowdowns, pressure relief valves, and other controlled sources and shall have a maximum design capacity of 19.8 mmscf/hr.

Condition 13.1.2.a. – Maximum aggregate combustion exhaust emissions from operation of the Flare shall not exceed the following during routine maintenance events, equipment blowdowns, from pressure relief valves, and other controlled sources.

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1,539.61	14.61
CO	3,073.64	29.17
$PM_{2.5}$/PM_{10}/PM	30.66	0.50
VOCs	22.19	0.36

Condition 13.1.2.b – Based on the minimum VOC DRE of 98% as given under Condition 13.1.7., maximum emissions of uncombusted pass-through VOCs and HAPs emitted at the Flare shall not exceed 10,153 lb/hr and 39.38 ton/yr of VOCs and 4.53 lb/hr and 0.12 ton/yr of HAPs.

Condition 13.1.3 – The total heat input of waste gases sent to the Flare during routine pigging events, equipment and site-wide blowdowns, the ethane treater flash tanks, irregular process vents, and from the closed vent system shall not exceed 197,459 mmBtu per rolling 12 month period.

Condition 13.1.4.a – No person shall cause, suffer, allow or permit PM to be discharged from any incinerator into the open air in excess of the quantity determined by use of the following formula: *Emissions (lbs/hr) = F x Incinerator Capacity (tons/yr)* where,

the factor F, is either 5.43 for a unit with a capacity of less than 15,000 lb/hr or 2.72 for a unit with a capacity of 15,000 lb/hr or greater. **[45CSR6 §4.1]**

Condition 13.1.4.b – No person shall cause or allow emission of smoke into atmosphere from the unit which is 20% opacity or higher. **[45CSR6 §4.3]**

Condition 13.1.4.c – The provisions of subsection Condition 13.1.4.b. shall not apply to smoke which is less than 40% opacity, for a period or periods aggregating no more than eight (8) minutes per start up. **[45CSR6 §4.4]**

Condition 13.1.4.d – No person shall cause, allow or permit the emission of particles of unburned or partially burned refuse or ash from the flare which are large enough to be individually distinguished in the open air.. **[45CSR6 §4.5]**

Condition 13.1.4.e – Flare shall be designed, operated, and maintained so as to prevent the emission of objectionable odors. **[45CSR6 §4.6]**

Condition 13.1.4.f – At such reasonable times as the Secretary may designate, the operator of any incinerator shall be required to conduct or have conducted stack tests to determine the particulate matter loading, by using 40 CFR Part 60, Appendix A, Method 5 or other equivalent U.S. EPA approved method approved by the Secretary, in exhaust gases. Such tests shall be conducted in such manner as the Secretary may specify and be filed on forms and in a manner acceptable to the Secretary. The Secretary may, at the Secretary's option, witness or conduct such stack tests. Should the Secretary exercise his or her option to conduct such tests, the operator will provide all the necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment such as scaffolding, railings and ladders to comply with generally accepted good safety practices. **[45CSR6 §7.1]**

Condition 13.1.4.g – The Secretary may conduct other tests as they may deem necessary to evaluate air pollution emissions other than those noted above. **[45CSR6 §7.2]**

Condition 13.1.4.h – Due to an unavoidable malfunction of equipment, emissions exceeding any limitation in this rule may be permitted by the Secretary for periods not to exceed five (5) days upon specific application to the Secretary. Such application shall be made within twenty-four (24) hours of the malfunction. In cases of major equipment failure, additional time periods may be granted by the Secretary provided a corrective program has been submitted by the owner or operator and approved by the Secretary. **[45CSR6 §8.2]**

Condition 13.1.5 – A pilot flame must be present at all times of operation of the Flare. The presence of a pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

Condition 13.1.7 – Flare shall be operated and designed in accordance with the information filed in permit application R13-2896K to achieve a VOC DRE of 98%

Condition 13.1.8 – The inlet flow rate of the Flare must be equal to or less than the maximum specified by the manufacturer.

Condition 13.1.9 – The permittee will comply with the requirements of Section 2.12 of this permit during emergency operation of the Flare

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 30-5.1.c.

To demonstrate compliance, presence or absence of a flare pilot flame shall be monitored

Method 22 Opacity testing shall be conducted within one year of permit issuance or initials startup, whichever is later

The Director may require a flare compliance assessment be conducted to demonstrate compliance

Maintain records of the times and duration of all periods in which the pilot flame was absent

Maintain a record of the flare design evaluation

Maintain records of the VE opacity testing conducted

Maintain records of the wet natural gas throughput through the dehydration system

Maintain monthly hours of operation records for the dehydration unit

Maintain records for a period of five years on site or an readily accessible off-site location

45 C.S.R. 13, Permit R13-2896K
Condition 13.2.1. – To demonstrate compliance with the requirements of 13.1.2, 13.1.3, and 13.1.4(a), the permittee shall monitor the aggregate throughput and heat input of waste gases sent to the flare on a monthly basis.

Condition 13.2.2. – To demonstrate compliance with the flame requirements of 13.1.5, the presence of a flame shall be continuously monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

Condition 13.2.3.a – To demonstrate compliance with the VE requirements of 45CSR6, the permittee shall conduct the following VE checks and/or opacity monitoring and recordkeeping for the unit

1. The VE check shall determine the presence or absence of VEs. The observations shall be conducted according to Section 11 of the EPA Method 22. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, and the presence of uncombined water on the visibility of emissions. The observation period shall be a minimum of one (1) hour each calendar month during flaring operations;
2. As the ground flare is of smokeless design, any observation of VEs will indicate incorrect operation of the flare. Therefore, upon the observation of VEs, the permittee shall, at the next available safe opportunity, cease operation of the flare and attempt to correct the problem. After an attempt to correct the problem, the permittee shall then conduct a minimum of one (1) hour of VE observations according to 13.2.3(a) during flaring operations;
3. The permittee shall maintain records of all monitoring data required by 13.2.3. documenting the date and time of each VE check, the emission point or equipment/source ID number, the name or means of identification of the observer, the results of the check(s), whether the VEs are normal for the process, and if applicable, all corrective measure taken or planned. The permittee shall also record the general weather conditions during the VE check;
4. Any deviation(s) from the allowable VE requirement for any emissions discovered during observations using 40 CFR Part 60, Appendix A, Method 9 or 22 shall be reported in writing to the Director of the DAQ as soon as practicable but in any case with ten calendar days of the occurrence.

Condition 13.2.4 – For the purpose of demonstrating compliance with Sections 13.1.5 and 13.2.2, the permittee shall maintain records of the times and duration of all periods which the pilot flame was absent.

Condition 13.2.5 – If permittee is required by the Director to demonstrate compliance with section 13.1.4(f) and 13.1.4(g), then the permittee shall submit a testing protocol at least 30 days prior to testing and shall submit a notification of the testing date at least 15 days prior to testing. The permittee shall submit the testing results within 60 days of testing and provide all supporting calculations and testing data.

Condition 13.2.6. – Any deviations from the flare design and operation criteria in section 13.1.7 and permit application R13-2896K, shall be reported in writing to the Director as soon as practicable but no later than 10 calendar days of discovery of such deviation.

Condition 13.2.7 – The permittee shall report to the Director, the time, cause of event, estimate of emissions and corrective actions taken when the unit was used for an emergency at the facility.

Are you in compliance with all applicable requirements for this emission unit? __✓_Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S006	Glycol Dehydration System	C001

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Glycol Dehydration Unit with Flash tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

460.0 mmscf/d

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
19.17 mmscf/hr	167,900 mmscf/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☒ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

N/A

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	1.78	7.80
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	2.89E-02	1.27E-01
N-Hexane	3.91E-02	1.71E-01
Benzene	3.04E-02	1.33E-01
Toluene	5.25E-02	2.30E-01
Total HAPs	1.51E-01	6.61E-01
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

GRI-GLYCalc Version 4.0

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 63 Subpart HH
40 C.F.R. § 63.764 (e)(1)(ii) – Less than one (1) ton of Benzene Exemption

40 C.F.R. § 63.772 – Compliance Procedures

40 C.F.R. § 63.774 – Recordkeeping Requirements

40 C.F.R. § 63.775 – Reporting Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 10.1.1 – Maximum aggregate wet natural gas throughput to the unit shall not exceed 460 mmscf/d or 167,900 mmscf/yr

Condition 10.1.2 – Maximum glycol recirculation rate in the unit shall not exceed 40 gpm

Condition 10.1.3.a. – Maximum aggregate controlled emissions from the unit including still vent and flash tank but not including the combustion exhaust emissions from the reboiler shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
VOCs	1.78	7.80
n-Hexane	0.04	0.17
Benzene	0.03	0.13
Toluene	0.05	0.23
Xylene	0.03	0.13
Total HAPs	0.15	0.66

(1) Emissions based on GLYCalc Version 4.0 using wet gas throughputs as limited under 10.1.1 and a 10% safety factor (on uncontrolled emissions)

Condition 10.1.4 – Still vent and flash tank vapors from the unit shall be routed to the Hot Oil Heater (S001:C001) and used as fuel.

Condition 10.1.5 – Exemptions; The owner/operator at an area source is exempt from the requirements of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that records of the determination of these criteria must be maintained as required in §63.774(d)(1);

a. The actual annual average flowrate of natural gas to the unit is less than 85,000 cubic meters per day as determined by procedures specified in §63.772(b)(1) of this subpart; or **[40CFR§63.764(e)(1)(i)]**
b. The actual average emissions of benzene from the unit to the atmosphere are less than 0.90 megagram per year as determined by the procedures specified in §63.772(b)(2) of this subpart **[40CFR§63.764(e)(1)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 63 Subpart HH
40 C.F.R. § 63.772(b)(2) – Permittee shall determine actual average Benzene emissions by using GRI-GLYCalc Version 3.0 or higher or by determining an average mass rate of benzene emissions in kg/hr through direct measurement.

40 C.F.R. § 63.774(d)(i) – Maintain records of actual average Benzene emissions

40 C.F.R. § 63.775(c)(8) – TEG Units located at an area source meeting the criteria found in 63.764(e)(1)(ii) are exempt from the reporting requirement

45 C.S.R. 13, Permit R13-2896K
Condition 10.2.1. – For the purposes of demonstrating compliance with Condition 10.1.1., permittee shall monitor and maintain monthly and rolling 12 month records of the wet gas throughput in the unit.

Condition 10.2.2. – Compliance with limitations set forth in Condition 10.1.2. shall be determined using an average of a minimum quarterly readings of the actual glycol pump(s) rate. If more than one pump is operating simultaneously then the rate of each operating pump shall be recorded and totaled for compliance purposes.

Condition 10.2.3 – Representative gas sample collection and analysis frequency for dehydration units shall be determined a set forth in the schedule provided in the following table;

Wet Gas Sampling and Analysis Frequency for Dehydration Units Based on Potential HAP Emission Rates	
Each dehydration unit exempt from §63.764(d) requirements and with federally enforceable controls	Upon request by the Secretary
Each dehydration unit exempt from §63.764(d) requirements and without federally enforceable controls	An initial compliance evaluation within 180 days of registration issuance or within 180 days of start-up of the unit, whichever is later

Condition 10.3.1. – Permittee shall sample wet natural gas in accordance with GPA Method 2166 and analyze the samples in accordance with GPA 2286

Condition 10.4.4. – Permittee shall maintain records of any testing that is conducted according to Section 10.3.

Condition 10.5.2. – Any bypass event of the registered control device must be reported in writing to the Director of the DAQ as soon as practicable, but within 10 calendar days, of the occurrence and shall include all pertinent information.

Condition 10.5.3. – Any time the air pollution control devices in not operating when emissions are vented to it shall be reported in writing to the Director of the DAQ as soon as practicable, but within 10 calendar days, of the discovery

Are you in compliance with all applicable requirements for this emission unit? _✓__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S008	Product Loading – Closed Loop S008	Vapor Return to Tank

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Liquids loading: Propane, Isobutane, Butane & Natural Gas Liquids (NGL), Natural Gasoline, Produced Water/Slop

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

35,000 gpm

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating:	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gasoline – 600 gpm (Truck) / 2000 gpm (Rail)
Propane – 3600 gpm (Truck) / 4000 gpm (Rail) / 4000 gpm (Barge)
Isobutane – 3600 gpm (Truck) / 4000 gpm (Rail)
Butanes – 3600 gpm (Truck) / 4000 gpm (Rail)
NGL – 3600 gpm (Truck) / 4000 gpm (Rail)

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	5.99	4.21
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
N-Hexane	6.68E-02	1.05E-02
Benzene	1.35E-02	2.13E-03
Toluene	1.38E-02	2.16E-03
Xylene	4.00E-03	6.29E-04
Ethylbenzene	7.79E-04	1.22E-04
Total HAPs	9.88E-02	1.55E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.1 – The maximum design capacity of material loading/unloading and maximum emissions associated emissions shall not exceed the following for the specific NGLs:

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)	VOC Emissions (lb/hr)	VOC Emissions (ton/yr)
S008	Propane	3,600	4,000	4,000	5.99	4.21
	Isobutane			No		
	Butanes					
	NGL					
	Natural Gasoline	600	2000	NA		

Condition 15.1.2 – The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.

Condition 15.1.3 – The main liquids loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutene, butanes, natural gasoline, or NGLs to truck or railcar and when loading propane to barge. Natural gasoline barge loading (S033) operations and Slop Oil/Produced water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.

Condition 15.1.4 – All truck loading of Slop/Oil and Produced Water shall be down using the submerged fill method. The "submerged fill method" shall, for the purposes of this permit, mean either bottom filling or filling by extending the pipe to near the bottom of the tank and as soon as practicable, below the level of liquid.

_x_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S010	Unpaved Roads	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Unpaved Roads

Manufacturer:	**Model number:**	**Serial number:**
Construction date:	**Installation date:** 2011	**Modification date(s):**

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		1.17
Particulate Matter (PM_{10})		11.69
Total Particulate Matter (TSP)		43.86
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
Benzene		
Toluene		
Xylene		
Total HAPS		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 17

45 CSR§17-3.1. – No person shall cause, suffer, allow or permit fugitive PM to be discharged beyond the boundary lines of the property on which the discharge originates or ay any public or residential location, which causes or contributes to statutory air pollution

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 17

45 CSR§17-3.2. – When a person is found in violation of this rule, the Director may require the person to utilize a system to minimize fugitive PM. This system to minimize fugitive PM may include, but is not limited to, the following;

a. Use, where practicable, of water or chemicals for control of PM in demolition of existing buildings or structures, construction operations, grading of roads or the clearing of land;
b. Application of asphalt, water or suitable chemicals on unpaved roads, material stockpiles and other surfaces which can create airborne PM;
c. Covering of material transport vehicles, or treatment of cargo, to prevent contents from dripping, sifting, leaking or otherwise escaping and becoming airborne, and prompt removal of tracked material from roads or streets; or
d. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of materials, including adequate containment methods during sandblasting, abrasive cleaning or other similar operations.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S011	Ethane Amine Regenerator	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Ethane Amine Regenerator

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

129.0 mmscf/d

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
5.38 mmscf/hr	47,085 mmscf/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☒ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	1.98	8.67
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Methanol	1.82	7.99
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs	1.82	7.99
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

ProMax

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 14.1.1 – The maximum sour ethane throughput to the unit shall not exceed 129 mmscf/d and 47,085 mmscf/yr (or alternatively 81,523 bbl/day and 29,755,895 bbl/yr of treated ethane). Compliance shall be determined using a 12 month rolling total.

Condition 14.1.2 – The unit shall be designed and operated in accordance with the following;

a. CO_2 will be removed from the ethane product in amine contacting system
b. The total ethane product shall be contacted with an amine solution in the amine contactor where the CO_2 in the ethane product is removed to less than 500 ppmw;
c. The rich amine from the contactor is regenerated in the amine regenerator where heat input is used to drive the CO2 and water overhead and vented to the atmosphere; and
d. The lean amine from the bottom of the regenerator is recycled back to the amine contactor.

Condition 14.1.3 – Off gas from the unit's flash tank shall be collected and sent to the ground flare (S004A) for combustion.

Condition 14.1.4 – Maximum methanol and VOC emissions from the unit shall not exceed 1.82 lbs/hr and 7.99 ton/yr and 1.98 lbs/hr and 8.67 ton/yr, respectively.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 14.2.1 – In order to show compliance with 14.1.1, the permittee shall either; (1) monitor and record the monthly and 12 month total throughput of sour ethane fed to the unit or (2) monitor and record the monthly and 12 month total throughput of total treated ethane from the unit.

Condition 14.2.3 – The permittee shall conduct, at a minimum of once per 12 month period, sampling of the inlet gas stream to the ethane amine units. The results of this test shall be used, with appropriate modeling techniques (such as use of ProMax software) to verify that the emissions of the unit are in compliance with those given under 14.1.4 and 14.1.5.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S012	Regen Gas Heater (9.7 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Regen Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2013	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

9.7 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 9.7 MMBtu/hr	**Type and Btu/hr rating of burners:** 9.7 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
10,097 scf/hr
88 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.80	3.50
Nitrogen Oxides (NO_X)	0.95	4.17
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.07	0.32
Particulate Matter (PM_{10})	0.07	0.32
Total Particulate Matter (TSP)	0.07	0.32
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.13E-04	3.12E-03
N-Hexane	5.99E-05	2.62E-04
Benzene	2.00E-05	8.75E-05
Toluene	3.23E-05	1.42E-04
Other HAPs	1.84E-05	8.06E-05
Total HAPs	8.44E-04	3.70E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 13, Permit R13-2896K
Condition 7.1.1 – MDHI for the unit shall not exceed 9.7 mmBtu/hr

Condition 7.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.95	4.17
CO	0.80	3.50
$PM_{2.5}$ / PM_{10} / PM(1)	0.07	0.32
VOCs	0.05	0.23

(1) Includes condensables

Condition 7.1.3 – To demonstrate compliance with Condition 7.1.2, the quantity of natural gas consumed shall not exceed 10,097 scf/hr and 88 x 10^6 scf/yr.

Condition 7.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 7.1.4.b – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 CSR§2-3.2 – Compliance shall be determined using Method 9

45 C.S.R. 13, Permit R13-2896K
Condition 7.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 7.1.4 at such reasonable times the Secretary may designate.

Condition 7.3.1. – Compliance with VE requirements of 7.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 7.4.1 – To demonstrate compliance with Conditions 7.1.1 through 7.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit 7.1.2,

Condition 7.4.2 – The permittee shall maintain records of all monitoring data required by Condition 7.2.1.

Condition 7.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S013	Cryo HMO Heater (26.3 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Cryo HMO Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2013	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

26.3 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
26.3 MMBtu		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 26.3 MMBtu/hr	**Type and Btu/hr rating of burners:** 26.3 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
27,377 scf/hr
240 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	2.17	9.49
Nitrogen Oxides (NO_X)	2.58	11.29
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.20	0.86
Particulate Matter (PM_{10})	0.20	0.86
Total Particulate Matter (TSP)	0.20	0.86
Sulfur Dioxide (SO_2)	0.02	0.08
Volatile Organic Compounds (VOC)	0.14	0.62
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	1.93E-03	8.47E-03
N-Hexane	1.19E-04	5.20E-04
Benzene	5.41E-05	2.37E-04
Toluene	8.77E-05	3.84E-04
Other HAPs	4.99E-05	2.18E-04
Total HAPs	2.24E-03	9.83E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 26.3 mmBtu/hr = 2.37 lb/hr] However the unit is subject to a more stringent emission limit of 0.20 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 26.3 mmBtu/hr = 81.53 lb/hr] However the unit is subject to a more stringent emission limit of 0.02 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 26.3 mmBtu/hr

Condition 6.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	2.58	11.29
CO	2.17	9.49
$PM_{2.5}$ / PM_{10} / PM(1)	0.20	0.86
SO_2	0.02	0.08
VOCs	0.14	0.62

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 27,377 scf/hr and 240 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2]**

Condition 6.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit 6.1.2,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S015	Slop Water Truck Loading	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Liquids loading: Produced Water/Slop Truck Loading

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

2,007,070 gal/yr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating:	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Slop Oil/Produced Water
2,007,070 gal/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	2.32	0.11
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.1 – The maximum design capacity of material loading/unloading and maximum emissions associated emissions shall not exceed the following for the specific NGLs:

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)	VOC Emissions (lb/hr)	VOC Emissions (ton/yr)
S015	Slop Oil/Produced Water	150	No	No	2.32	0.11

Condition 15.1.2 – The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.

Condition 15.1.3 – The main liquids loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutene, butanes, natural gasoline, or NGLs to truck or railcar and when loading propane to barge. Natural gasoline barge loading (S033) operations and Slop Oil/Produced water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.

Condition 15.1.4 – All truck loading of Slop/Oil and Produced Water shall be down using the submerged fill method. The "submerged fill method" shall, for the purposes of this permit, mean either bottom filling or filling by extending the pipe to near the bottom of the tank and as soon as practicable, below the level of liquid.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S016	Hot Oil Heater (61.6 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2014	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

61.6 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 61.6 MMBtu/hr	**Type and Btu/hr rating of burners:** 61.6 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
64,101 scf/hr
562 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100ft3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.63	15.91
Nitrogen Oxides (NO_X)	1.48	6.47
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.46	2.01
Particulate Matter (PM_{10})	0.46	2.01
Total Particulate Matter (TSP)	0.46	2.01
Sulfur Dioxide (SO_2)	0.04	0.19
Volatile Organic Compounds (VOC)	0.33	1.45
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.53E-03	1.98E-02
N-Hexane	2.78E-04	1.22E-03
Benzene	1.27E-04	5.55E-04
Toluene	2.05E-04	8.99E-04
Other HAPs	1.17E-04	5.12E-04
Total HAPs	5.25E-03	2.30E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2. – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 61.6 mmBtu/hr = 5.54 lb/hr] However the unit is subject to a more stringent emission limit of 0.46 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2. – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 61.6 mmBtu/hr = 190.96 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 61.58 mmBtu/hr. Unit shall also be equipped with a Low-NOx burner.

Condition 5.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.48	6.47
CO	3.63	15.91
$PM_{2.5}$ / PM_{10} / PM(1)	0.46	2.01
SO_2	0.04	0.19
VOCs	0.33	1.45

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 64,101 scf/hr and 562 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2]**

Condition 5.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 5.1.6. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S017	Hot Oil Heater (61.6 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2014	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

61.6 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 61.6 MMBtu/hr	**Type and Btu/hr rating of burners:** 61.6 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
64,101 scf/hr
562 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100ft3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.63	15.91
Nitrogen Oxides (NO_X)	1.48	6.47
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.46	2.01
Particulate Matter (PM_{10})	0.46	2.01
Total Particulate Matter (TSP)	0.46	2.01
Sulfur Dioxide (SO_2)	0.04	0.19
Volatile Organic Compounds (VOC)	0.33	1.45
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.53E-03	1.98E-02
N-Hexane	2.78E-04	1.22E-03
Benzene	1.27E-04	5.55E-04
Toluene	2.05E-04	8.99E-04
Other HAPs	1.17E-04	5.12E-04
Total HAPs	5.25E-03	2.30E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2. – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 61.6 mmBtu/hr = 5.54 lb/hr] However the unit is subject to a more stringent emission limit of 0.46 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2. – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 61.6 mmBtu/hr = 190.96 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 61.58 mmBtu/hr. Unit shall also be equipped with a Low-NOx burner.

Condition 5.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.48	6.47
CO	3.63	15.91
$PM_{2.5}$ / PM_{10} / PM(1)	0.46	2.01
SO_2	0.04	0.19
VOCs	0.33	1.45

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 64,101 scf/hr and 562 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2]**

Condition 5.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 5.1.6. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S018	Hot Oil Heater (61.6 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2014	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

61.6 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 61.6 MMBtu/hr	**Type and Btu/hr rating of burners:** 61.6 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
64,101 scf/hr
562 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100ft3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.63	15.91
Nitrogen Oxides (NO_X)	1.48	6.47
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.46	2.01
Particulate Matter (PM_{10})	0.46	2.01
Total Particulate Matter (TSP)	0.46	2.01
Sulfur Dioxide (SO_2)	0.04	0.19
Volatile Organic Compounds (VOC)	0.33	1.45
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.53E-03	1.98E-02
N-Hexane	2.78E-04	1.22E-03
Benzene	1.27E-04	5.55E-04
Toluene	2.05E-04	8.99E-04
Other HAPs	1.17E-04	5.12E-04
Total HAPs	5.25E-03	2.30E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2. – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 61.6 mmBtu/hr = 5.54 lb/hr] However the unit is subject to a more stringent emission limit of 0.46 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2. – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 61.6 mmBtu/hr = 190.96 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 61.58 mmBtu/hr. Unit shall also be equipped with a Low-NOx burner.

Condition 5.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.48	6.47
CO	3.63	15.91
$PM_{2.5}$ / PM_{10} / PM(1)	0.46	2.01
SO_2	0.04	0.19
VOCs	0.33	1.45

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 64,101 scf/hr and 562 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2]**

Condition 5.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 5.1.6. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S019	Hot Oil Heater (61.6 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2014	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

61.6 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 61.6 MMBtu/hr	**Type and Btu/hr rating of burners:** 61.6 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
64,101 scf/hr
562 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100ft3	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.63	15.91
Nitrogen Oxides (NO_X)	1.48	6.47
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.46	2.01
Particulate Matter (PM_{10})	0.46	2.01
Total Particulate Matter (TSP)	0.46	2.01
Sulfur Dioxide (SO_2)	0.04	0.19
Volatile Organic Compounds (VOC)	0.33	1.45
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.53E-03	1.98E-02
N-Hexane	2.78E-04	1.22E-03
Benzene	1.27E-04	5.55E-04
Toluene	2.05E-04	8.99E-04
Other HAPs	1.17E-04	5.12E-04
Total HAPs	5.25E-03	2.30E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2. – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 61.6 mmBtu/hr = 5.54 lb/hr] However the unit is subject to a more stringent emission limit of 0.46 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2. – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 61.6 mmBtu/hr = 190.96 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 61.58 mmBtu/hr. Unit shall also be equipped with a Low-NOx burner.

Condition 5.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.48	6.47
CO	3.63	15.91
$PM_{2.5}$ / PM_{10} / PM(1)	0.46	2.01
SO_2	0.04	0.19
VOCs	0.33	1.45

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 64,101 scf/hr and 562 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2]**

Condition 5.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 5.1.6. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S024	Regen Gas Heater (9.7 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Regen Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2018	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

9.7 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
9.7 MMBtu		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 9.7 MMBtu/hr	**Type and Btu/hr rating of burners:** 9.7 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
10,097 scf/hr
88 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.80	3.50
Nitrogen Oxides (NO_X)	0.95	4.17
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.07	0.32
Particulate Matter (PM_{10})	0.07	0.32
Total Particulate Matter (TSP)	0.07	0.32
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.13E-04	3.12E-03
N-Hexane	5.99E-05	2.62E-04
Benzene	2.00E-05	8.75E-05
Toluene	3.23E-05	1.42E-04
Other HAPs	1.84E-05	8.06E-05
Total HAPs	8.44E-04	3.70E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 13, Permit R13-2896K
Condition 7.1.1 – MDHI for the unit shall not exceed 9.7 mmBtu/hr

Condition 7.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.95	4.17
CO	0.80	3.50
$PM_{2.5}$ / PM_{10} / PM(1)	0.07	0.32
VOCs	0.05	0.23

(1) Includes condensables

Condition 7.1.3 – To demonstrate compliance with Condition 7.1.2, the quantity of natural gas consumed shall not exceed 10,097 scf/hr and 88 x 10^6 scf/yr.

Condition 7.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 7.1.4.b – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 CSR§2-3.2 – Compliance shall be determined using Method 9

45 C.S.R. 13, Permit R13-2896K
Condition 7.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 7.1.4 at such reasonable times the Secretary may designate.

Condition 7.3.1. – Compliance with VE requirements of 7.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 7.4.1 – To demonstrate compliance with Conditions 7.1.1 through 7.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit 7.1.2,

Condition 7.4.2 – The permittee shall maintain records of all monitoring data required by Condition 7.2.1.

Condition 7.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S026	Cryo HMO Heater (26.3 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Cryo HMO Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2018	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

26.3 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
26.3 MMBtu		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 26.3 MMBtu/hr	**Type and Btu/hr rating of burners:** 26.3 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
27,377 scf/hr
240 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	2.17	9.49
Nitrogen Oxides (NO_X)	2.58	11.29
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.20	0.86
Particulate Matter (PM_{10})	0.20	0.86
Total Particulate Matter (TSP)	0.20	0.86
Sulfur Dioxide (SO_2)	0.02	0.08
Volatile Organic Compounds (VOC)	0.14	0.62
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	1.93E-03	8.47E-03
N-Hexane	1.19E-04	5.20E-04
Benzene	5.41E-05	2.37E-04
Toluene	8.77E-05	3.84E-04
Other HAPs	4.99E-05	2.18E-04
Total HAPs	2.24E-03	9.83E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2. – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 26.3 mmBtu/hr = 2.37 lb/hr] However the unit is subject to a more stringent emission limit of 0.20 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2. – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5. – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 26.3 mmBtu/hr = 81.53 lb/hr] However the unit is subject to a more stringent emission limit of 0.02 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 26.3 mmBtu/hr

Condition 6.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	2.58	11.29
CO	2.17	9.49
$PM_{2.5}$ / PM_{10} / PM(1)	0.20	0.86
SO_2	0.02	0.08
VOCs	0.14	0.62

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 27,377 scf/hr and 240 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2.]**

Condition 6.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit 6.1.2,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S033	Barge Loading Vent	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Liquids loading at Barge: Natural Gasoline

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2017	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

408,240,000 gal/yr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating:	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gasoline
408,240,000 gal/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	97.22	82.69
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Benzene	4.38E-01	3.72E-01
Toluene	7.29E-01	6.20E-01
Xylene	2.82E-01	2.40E-01
Total HAPs	1.45E+00	1.23E+00
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.1 – The maximum design capacity of material loading/unloading and maximum emissions associated emissions shall not exceed the following for the specific NGLs:

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)	VOC Emissions (lb/hr)	VOC Emissions (ton/yr)
S033	Natural Gasoline	n/a	n/a	4000	97.22	82.69

Condition 15.1.2 – The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.

Condition 15.1.3 – The main liquids loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutene, butanes, natural gasoline, or NGLs to truck or railcar and when loading propane to barge. Natural gasoline barge loading (S033) operations and Slop Oil/Produced water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.

Condition 15.1.4 – All truck loading of Slop/Oil and Produced Water shall be down using the submerged fill method. The "submerged fill method" shall, for the purposes of this permit, mean either bottom filling or filling by extending the pipe to near the bottom of the tank and as soon as practicable, below the level of liquid.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S034, S035	Pigging Operations	C034 Flare

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Pigging Operations including a waste gas combustion

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2017	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

72,000 scf/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☒ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 170.71 mmBtu/hr	**Type and Btu/hr rating of burners:** 170.71 mmBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Propane / Butane Gas
72,000 scf/hr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.25 gr/100 ft^3	N/A	2,371 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	13.99	0.07
Nitrogen Oxides (NO_X)	24.25	0.12
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	1.31	0.01
Particulate Matter (PM_{10})	1.31	0.01
Total Particulate Matter (TSP)	1.31	0.01
Sulfur Dioxide (SO_2)	1.87	0.01
Volatile Organic Compounds (VOC)	330.87	1.98
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
N-Hexane	1.20E+00	9.54E-03
Benzene	1.79E-02	1.55E-04
Toluene	2.50E-02	2.16E-04
Xylene	8.88E-03	7.67E-05
Total HAPs	1.25E+00	9.99E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.5 – Liquefied Petroleum Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 6
45 C.S.R. 6-4.1 – Particulate Matter Emission Limitation; The total allowable emission rate of PM for the unit shall be calculated using the following equation; Emissions (lb/hr) = F x Incinerator Capacity (tons/hr) where the F factor has a value of 5.43 for incinerators with capacity of greater than 15,000 lbs/hr. The PM Emission Limit for this unit will be 8.24 lb/hr [5.43 x IC (1.52) ton/hr = 8.24 lb/hr].

45 C.S.R. 6-4.3 – Opacity Limitations; No person shall cause or allow emission of smoke into atmosphere from the unit which is 20% opacity or higher.

45 C.S.R. 6-4.4 – Opacity Limitations during Startup; The provisions of subsection 4.3 shall not apply to smoke which is less than 40% opacity, for a period or periods aggregating no more than eight (8) minutes per start up.

45 C.S.R. 6-4.5 – Refuse/Ash; No person shall cause, allow or permit the emission of particles of unburned or partially burned refuse or ash from the flare which are large enough to be individually distinguished in the open air.

45 C.S.R. 6-4.6 – Objectionable Odors; Flare shall be designed, operated, and maintained so as to prevent the emission of objectionable odors

45 C.S.R. 30-12.7
Flare shall be steam-assisted, air-assisted, or non-assisted.

Flare shall be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Flare shall be operated with a flame present at all times except during SSM.

Flare shall be designed to meet the Btu and exit velocity requirements in accordance with 63.11.

45 C.S.R. 13, Permit R13-2896K
Condition 16.1.1. – Permittee shall utilize a non-assisted flare for control of potential emissions during all times of propane pig trap operations. The flare will have a maximum design capacity of 72,000 scf/hr and be designed and operated to achieve a minimum propane DRE of 98%.

Condition 16.1.2. – The maximum annual combustion of waste gases in the pig trap flare shall not exceed 720,000 scf. The maximum number of pigging events per year for all pig traps shall not exceed the limits and volumes per event (scf) established in the permit application R13-2896K.

Condition 16.1.3. – Maximum combustion exhaust emissions (not including uncombusted pass through emissions of waste gases) from S034 shall not exceed the following;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	24.25	0.12
CO	13.99	0.07
$PM_{2.5}/PM_{10}/PM$	1.31	0.01

Condition 16.1.4 – Based on the minimum VOC DRE of 98% as required under Condition 16.1.1., maximum emissions of uncombusted VOCs emitted at the Pigging Flare shall not exceed 227.77 lb/hr and 1.14 ton.yr of VOCs. The maximum emissions of VOCs and HAPs emitted from all other pigging operations with the exception of the propane pig trap shall not exceed 103.10 lbs/hr and 0.84 tons/yr, and 1.25 lbs/hr and 0.01 tons/yr, respectively.

Condition 16.1.5 – The pigging vapors from the three (3) truck side 30" Inlet Receivers shall be captured by the VRUand routed back to the process.

Condition 16.1.6. The Pigging Flare shall be designed and operated in accordance with 40 CFR 60, Section 60.18.

Condition 16.1.7 – The Pigging Flare is subject to 45CSR6. The requirements of 45CSR6 include but are not limited to those given under Condition 13.1.4.

__X__ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 30-5.1.c.

To demonstrate compliance, presence or absence of a flare pilot flame shall be monitored continuously and recorded

Method 22 Opacity testing shall be conducted within one year of permit issuance or initials startup, whichever is later

Maintain records of the times and duration of all periods in which the pilot flame was absent

Maintain a record of the flare design evaluation

Maintain records for a period of five years on site or an readily accessible off-site location

45 C.S.R. 13, Permit R13-2896K
Condition 16.2.1. – In order to show compliance with Condition 16.1.2., the permittee shall calculate, based on the information collected under 16.2.2, the throughput (in scf) of waste gases fed to S034 on a monthly and a rolling 12 month basis..

Condition 16.2.2. – In order to show compliance with 16.1.2, the permittee shall monitor and record the total number and type of pigging events and the estimated volume per event (in scf) on a monthly and rolling 12 month total for all pig traps.

Condition 16.2.3.a – To demonstrate compliance with the VE requirements of 45CSR6, the permittee shall conduct the following VE checks and/or opacity monitoring and recordkeeping for the unit

1. The VE check shall determine the presence or absence of VEs. The observations shall be conducted according to Section 11 of the EPA Method 22. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, and the presence of uncombined water on the visibility of emissions. The observation period shall be a minimum of one (1) hour at initial commissioning and at least one (1) hour thereafter each calendar year during a pig trap flaring operation;
2. As the unit is of smokeless design, any observation of VEs will indicate incorrect operation of the flare. Therefore, upon the observation of VEs, the permittee shall, at the next available safe opportunity, cease operation of the flare and attempt to correct the problem. After an attempt to correct the problem, the permittee shall then conduct a minimum of one (1) hour of VE observations according to 16.2.3(a)(1) during the next pig trap flaring operations; and
3. The permittee shall maintain records of all monitoring data required by 16.2.3. documenting the date and time of each VE check, the emission point or equipment/source ID number, the name or means of identification of the observer, the results of the check(s), whether the VEs are normal for the process, and if applicable, all corrective measure taken or planned. The permittee shall also record the general weather conditions during the VE check;

Are you in compliance with all applicable requirements for this emission unit? _✓__Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S036	Regen Gas Heater (9.7 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Regen Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

9.7 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 9.7 MMBtu/hr	**Type and Btu/hr rating of burners:** 9.7 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
10,097 scf/hr
88 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.80	3.50
Nitrogen Oxides (NO_X)	0.95	4.17
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.07	0.32
Particulate Matter (PM_{10})	0.07	0.32
Total Particulate Matter (TSP)	0.07	0.32
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.13E-04	3.12E-03
N-Hexane	5.99E-05	2.62E-04
Benzene	2.00E-05	8.75E-05
Toluene	3.23E-05	1.42E-04
Other HAPs	1.84E-05	8.06E-05
Total HAPs	8.44E-04	3.70E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 13, Permit R13-2896K
Condition 7.1.1 – MDHI for the unit shall not exceed 9.7 mmBtu/hr

Condition 7.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.95	4.17
CO	0.80	3.50
$PM_{2.5}$ / PM_{10} / PM(1)	0.07	0.32
VOCs	0.05	0.23

(1) Includes condensables

Condition 7.1.3 – To demonstrate compliance with Condition 7.1.2, the quantity of natural gas consumed shall not exceed 10,097 scf/hr and 88 x 10^6 scf/yr.

Condition 7.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 7.1.4.b – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 CSR§2-3.2 – Compliance shall be determined using Method 9

45 C.S.R. 13, Permit R13-2896K
Condition 7.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 7.1.4 at such reasonable times the Secretary may designate.

Condition 7.3.1. – Compliance with VE requirements of 7.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 7.4.1 – To demonstrate compliance with Conditions 7.1.1 through 7.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit 7.1.2,

Condition 7.4.2 – The permittee shall maintain records of all monitoring data required by Condition 7.2.1.

Condition 7.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S037	Cryo HMO Heater (26.3 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Cryo HMO Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

26.3 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
26.3 MMBtu		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 26.3 MMBtu/hr	**Type and Btu/hr rating of burners:** 26.3 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
27,377 scf/hr
240 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	2.17	9.49
Nitrogen Oxides (NO_X)	2.58	11.29
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.20	0.86
Particulate Matter (PM_{10})	0.20	0.86
Total Particulate Matter (TSP)	0.20	0.86
Sulfur Dioxide (SO_2)	0.02	0.08
Volatile Organic Compounds (VOC)	0.14	0.62
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	1.93E-03	8.47E-03
N-Hexane	1.19E-04	5.20E-04
Benzene	5.41E-05	2.37E-04
Toluene	8.77E-05	3.84E-04
Other HAPs	4.99E-05	2.18E-04
Total HAPs	2.24E-03	9.83E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2. – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 26.3 mmBtu/hr = 2.37 lb/hr] However the unit is subject to a more stringent emission limit of 0.20 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2. – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1. and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5. – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 26.3 mmBtu/hr = 81.53 lb/hr] However the unit is subject to a more stringent emission limit of 0.02 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§10.6 – Unit shall be registered with the Director within 30 days of commencement of construction

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 26.3 mmBtu/hr

Condition 6.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	2.58	11.29
CO	2.17	9.49
$PM_{2.5}$ / PM_{10} / PM(1)	0.20	0.86
SO_2	0.02	0.08
VOCs	0.14	0.62

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 27,377 scf/hr and 240 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1.2.]**

Condition 6.1.4.c – Visible emission standards set forth in Section 3 of 45CSR2 shall apply at all times except in periods of start-ups, shutdowns, and malfunctions **[45CSR§2-9.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3. – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1. – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit 6.1.2,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S040	Regen Gas Heater (19.28 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Regen Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

19.28 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 19.28 MMBtu/hr	**Type and Btu/hr rating of burners:** 19.28 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
20,069 scf/hr
176 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	1.59	6.95
Nitrogen Oxides (NO_X)	1.89	8.28
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.14	0.63
Particulate Matter (PM_{10})	0.14	0.63
Total Particulate Matter (TSP)	0.14	0.63
Sulfur Dioxide (SO_2)	0.01	0.06
Volatile Organic Compounds (VOC)	0.10	0.46
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	1.42E-03	6.21E-03
N-Hexane	8.69E-05	3.81E-04
Benzene	3.97E-05	1.74E-04
Toluene	6.43E-05	2.81E-04
Other HAPs	3.66E-05	1.60E-04
Total HAPs	1.65E-03	7.21E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 19.28 mmBtu/hr = 59.77 lb/hr]

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

45 C.S.R. 13, Permit R13-2896K
Condition 7.1.1 – MDHI for the unit shall not exceed 19.28 mmBtu/hr

Condition 7.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.89	8.28
CO	1.59	6.95
$PM_{2.5}$ / PM_{10} / PM(1)	0.14	0.63
VOCs	0.10	0.46

(1) Includes condensables

Condition 7.1.3 – To demonstrate compliance with Condition 7.1.2, the quantity of natural gas consumed shall not exceed 20,069 scf/hr and 176 x 10^6 scf/yr.

Condition 7.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2

45 CSR§2-3.2 – Compliance shall be determined using Method 9

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

45 C.S.R. 13, Permit R13-2896K

Condition 7.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 7.1.4 at such reasonable times the Secretary may designate.

Condition 7.3.1. – Compliance with VE requirements of 7.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 7.4.1 – To demonstrate compliance with Conditions 7.1.1 through 7.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 7.4.2 – The permittee shall maintain records of all monitoring data required by Condition 7.2.1.

Condition 7.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S044	Regen Gas Heater (9.7 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Regen Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

9.7 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 9.7 MMBtu/hr	**Type and Btu/hr rating of burners:** 9.7 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
10,097 scf/hr
88 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.80	3.50
Nitrogen Oxides (NO_X)	0.95	4.17
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.07	0.32
Particulate Matter (PM_{10})	0.07	0.32
Total Particulate Matter (TSP)	0.07	0.32
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.13E-04	3.12E-03
N-Hexane	5.99E-05	2.62E-04
Benzene	2.00E-05	8.75E-05
Toluene	3.23E-05	1.42E-04
Other HAPs	1.84E-05	8.06E-05
Total HAPs	8.44E-04	3.70E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 13, Permit R13-2896K
Condition 7.1.1 – MDHI for the unit shall not exceed 9.7 mmBtu/hr

Condition 7.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.95	4.17
CO	0.80	3.50
$PM_{2.5}$ / PM_{10} / PM(1)	0.07	0.32
VOCs	0.05	0.23

(1) Includes condensables

Condition 7.1.3 – To demonstrate compliance with Condition 7.1.2, the quantity of natural gas consumed shall not exceed 10,097 scf/hr and 88 x 10^6 scf/yr.

Condition 7.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 CSR§2-3.2 – Compliance shall be determined using Method 9

45 C.S.R. 13, Permit R13-2896K
Condition 7.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 7.1.4 at such reasonable times the Secretary may designate.

Condition 7.3.1. – Compliance with VE requirements of 7.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 7.4.1 – To demonstrate compliance with Conditions 7.1.1 through 7.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 7.4.2 – The permittee shall maintain records of all monitoring data required by Condition 7.2.1.

Condition 7.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S045	Cryo HMO Heater (26.3 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Cryo HMO Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

26.3 MMBtu

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
26.3 MMBtu/hr		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 26.3 MMBtu/hr	**Type and Btu/hr rating of burners:** 26.3 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
27,377 scf/hr
240 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	2.17	9.49
Nitrogen Oxides (NO_X)	2.58	11.29
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.20	0.86
Particulate Matter (PM_{10})	0.20	0.86
Total Particulate Matter (TSP)	0.20	0.86
Sulfur Dioxide (SO_2)	0.02	0.08
Volatile Organic Compounds (VOC)	0.14	0.62
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	1.93E-03	8.47E-03
N-Hexane	1.19E-04	5.20E-04
Benzene	5.41E-05	2.37E-04
Toluene	8.77E-05	3.84E-04
Other HAPs	4.99E-05	2.18E-04
Total HAPs	2.24E-03	9.83E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 26.3 mmBtu/hr = 2.37 lb/hr] However the unit is subject to a more stringent emission limit of 0.20 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1 and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/ hr [3.1 x 26.3 mmBtu/hr = 81.53 lb/hr] However the unit is subject to a more stringent emission limit of 0.02 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 26.3 mmBtu/hr

Condition 6.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	2.58	11.29
CO	2.17	9.49
$PM_{2.5}$ / PM_{10} / PM(1)	0.20	0.86
SO_2	0.02	0.08
VOCs	0.14	0.62

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 27,377 scf/hr and 240 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S048	Regen Gas Heater (9.7 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Regen Gas Heater, Indirect heat exchanger

Vertical Stack

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

9.7 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
9.7 MMBtu/hr		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 9.7 MMBtu/hr	**Type and Btu/hr rating of burners:** 9.7 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
10,097 scf/hr
88 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.80	3.50
Nitrogen Oxides (NO_X)	0.95	4.17
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.07	0.32
Particulate Matter (PM_{10})	0.07	0.32
Total Particulate Matter (TSP)	0.07	0.32
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.23
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.13E-04	3.12E-03
N-Hexane	5.99E-05	2.62E-04
Benzene	2.00E-05	8.75E-05
Toluene	3.23E-05	1.42E-04
Other HAPs	1.84E-05	8.06E-05
Total HAPs	8.44E-04	3.70E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 C.S.R. 13, Permit R13-2896K
Condition 7.1.1 – MDHI for the unit shall not exceed 9.7 mmBtu/hr

Condition 7.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.95	4.17
CO	0.80	3.50
$PM_{2.5}$ / PM_{10} / PM(1)	0.07	0.32
VOCs	0.05	0.23

(1) Includes condensables

Condition 7.1.3 – To demonstrate compliance with Condition 7.1.2, the quantity of natural gas consumed shall not exceed 10,097 scf/hr and 88 x 10^6 scf/yr.

Condition 7.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 CSR§2-3.2 – Compliance shall be determined using Method 9

45 C.S.R. 13, Permit R13-2896K
Condition 7.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 7.1.4 at such reasonable times the Secretary may designate.

Condition 7.3.1. – Compliance with VE requirements of 7.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 7.4.1 – To demonstrate compliance with Conditions 7.1.1 through 7.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 7.4.2 – The permittee shall maintain records of all monitoring data required by Condition 7.2.1.

Condition 7.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S049	Cryo HMO Heater (26.3 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Cryo HMO Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

26.3 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
26.3 MMBtu/hr		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 26.3 MMBtu/hr	**Type and Btu/hr rating of burners:** 26.3 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
27,377 scf/hr
240 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	2.17	9.49
Nitrogen Oxides (NO_X)	2.58	11.29
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.20	0.86
Particulate Matter (PM_{10})	0.20	0.86
Total Particulate Matter (TSP)	0.20	0.86
Sulfur Dioxide (SO_2)	0.02	0.08
Volatile Organic Compounds (VOC)	0.14	0.62
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	1.93E-03	8.47E-03
N-Hexane	1.19E-04	5.20E-04
Benzene	5.41E-05	2.37E-04
Toluene	8.77E-05	3.84E-04
Other HAPs	4.99E-05	2.18E-04
Total HAPs	2.24E-03	9.83E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 26.3 mmBtu/hr = 2.37 lb/hr] However the unit is subject to a more stringent emission limit of 0.20 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.a and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 26.3 mmBtu/hr = 81.53 lb/hr] However the unit is subject to a more stringent emission limit of 0.02 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.a.

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 26.3 mmBtu/hr

Condition 6.1.2.a. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	2.58	11.29
CO	2.17	9.49
$PM_{2.5}$ / PM_{10} / PM(1)	0.20	0.86
SO_2	0.02	0.08
VOCs	0.14	0.62

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 27,377 scf/hr and 240 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.c3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S052	Hot Oil Heater (61.6 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

61.6 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
61.6 MMBtu/hr		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 61.6 MMBtu/hr	**Type and Btu/hr rating of burners:** 61.6 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
64,101 scf/hr
562 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.63	15.91
Nitrogen Oxides (NO_X)	1.48	6.47
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.46	2.01
Particulate Matter (PM_{10})	0.46	2.01
Total Particulate Matter (TSP)	0.46	2.01
Sulfur Dioxide (SO_2)	0.04	0.19
Volatile Organic Compounds (VOC)	0.33	1.45
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.53E-03	1.98E-02
N-Hexane	2.78E-04	1.22E-03
Benzene	1.27E-04	5.55E-04
Toluene	2.05E-04	8.99E-04
Other HAPs	1.17E-04	5.12E-04
Total HAPs	5.25E-03	2.30E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 61.6 mmBtu/hr = 5.54 lb/hr] However the unit is subject to a more stringent emission limit of 0.46 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1 and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 61.6 mmBtu/hr = 190.96 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 61.58 mmBtu/hr. Unit shall also be equipped with a Low-NOx burner.

Condition 5.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.48	6.47
CO	3.63	15.91
$PM_{2.5}$ / PM_{10} / PM(1)	0.46	2.01
SO_2	0.04	0.19
VOCs	0.33	1.45

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 64,101 scf/hr and 562 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1]**

Condition 5.1.6. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S053	Hot Oil Heater (61.6 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Hot Oil Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

61.6 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
61.6 MMBtu/hr		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 61.6 MMBtu/hr	**Type and Btu/hr rating of burners:** 61.6 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
64,101 scf/hr
562 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	3.63	15.91
Nitrogen Oxides (NO_X)	1.48	6.47
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.46	2.01
Particulate Matter (PM_{10})	0.46	2.01
Total Particulate Matter (TSP)	0.46	2.01
Sulfur Dioxide (SO_2)	0.04	0.19
Volatile Organic Compounds (VOC)	0.33	1.45
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.53E-03	1.98E-02
N-Hexane	2.78E-04	1.22E-03
Benzene	1.27E-04	5.55E-04
Toluene	2.05E-04	8.99E-04
Other HAPs	1.17E-04	5.12E-04
Total HAPs	5.25E-03	2.30E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 61.6 mmBtu/hr = 5.54 lb/hr] However the unit is subject to a more stringent emission limit of 0.46 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 5.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1 and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 61.6 mmBtu/hr = 190.96 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K Condition 5.1.2.b.

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 5.1.1 – MDHI for the unit shall not exceed 61.58 mmBtu/hr. Unit shall also be equipped with a Low-NOx burner.

Condition 5.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	1.48	6.47
CO	3.63	15.91
$PM_{2.5}$ / PM_{10} / PM(1)	0.46	2.01
SO_2	0.04	0.19
VOCs	0.33	1.45

(1) Includes condensables

Condition 5.1.3 – To demonstrate compliance with Condition 5.1.2, the quantity of natural gas consumed shall not exceed 64,101 scf/hr and 562 x 10^6 scf/yr.

Condition 5.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 5.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1]**

Condition 5.1.6. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.c3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 5.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 5.1.4 at such reasonable times the Secretary may designate.

Condition 5.3.1. – The permittee shall conduct test(s) to determine compliance with emission limitations under 5.1.2 at such reasonable times as the Secretary may designate.

Condition 5.4.1 – To demonstrate compliance with Conditions 5.1.1 through 5.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit.

Condition 5.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S054	Ethane Amine Regenerator	C011 (VRU)

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Ethane Amine Regenerator

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

129.0 mmscf/d

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
5.38 mmscf/hr	**47,085 mmscf/yr**	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☒ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	1.98	0.43
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Methanol	1.82E+00	4.00E-01
Total HAPs	1.82E+00	4.00E-01
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

ProMax

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 14.1.1 – The maximum sour ethane throughput to the unit shall not exceed 129 mmscf/d and 47,085 mmscf/yr (or alternatively 81,523 bbl/day and 29,755,895 bbl/yr of treated ethane). Compliance shall be determined using a 12 month rolling total.

Condition 14.1.2 – The unit shall be designed and operated in accordance with the following;

a. CO_2 will be removed from the ethane product in amine contacting system
b. The total ethane product shall be contacted with an amine solution in the amine contactor where the CO_2 in the ethane product is removed to less than 500 ppmw;
c. The rich amine from the contactor is regenerated in the amine regenerator where heat input is used to drive the CO2 and water overhead and vented to the VRU and
d. The lean amine from the bottom of the regenerator is recycled back to the amine contactor.

Condition 14.1.3 – Off gas from the unit's flash tank shall be collected and sent to the ground flare (S004A) for combustion.

Condition 14.1.5 – The still vent emissions from the unit shall be, at a minimum of 95% of the time the unit is in operation, captured by the VRU (C011) and routed to the residue gas discharge line. During VRU downtime, emissions from the unit shall vent to the atmosphere. Maximum methanol and VOC emissions from the unit shall not exceed 1.82 lbs/hr and 0.40 ton/yr and 1.98 lbs/hr and 0.43 ton/yr, respectively

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 14.2.1 – In order to show compliance with 14.1.1, the permittee shall either; (1) monitor and record the monthly and 12 month total throughput of sour ethane fed to the unit or (2) monitor and record the monthly and 12 month total throughput of total treated ethane from the unit.

Condition 14.2.2 – The permittee shall monitor and record the monthly and 12 month total percentage of time the unit is operated when the VRU is not in operation.

Condition 14.2.3 – The permittee shall conduct, at a minimum of once per 12 month period, sampling of the inlet gas stream to the ethane amine units. The results of this test shall be used, with appropriate modeling techniques (such as use of ProMax software) to verify that the emissions of the unit are in compliance with those given under 14.1.4 and 14.1.5.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S055	Pressurized NGL/Condensate S055	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Pressurized NGL/Condensate liquid transfer operation.

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2012	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

3,600 gpm.

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating:	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Pressurized NGL / Condensate
3,600 gpm

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	6.64	14.54
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
N-Hexane	3.40E-01	7.45E-01
Total HAPs	3.40E-01	7.45E-01
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.1 – The maximum design capacity of material loading/unloading and maximum emissions associated emissions shall not exceed the following for the specific NGLs:

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)	VOC Emissions (lb/hr)	VOC Emissions (ton/yr)
S055	Pressurized NGL/Condensate (Unloading)	3600	n/a	No	6.64	14.54

Condition 15.1.2 – The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.

Condition 15.1.3 – The main liquids loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutane, butanes, natural gasoline, or NGLs to truck or railcar and when loading propane to barge. Natural gasoline barge loading (S033) operations and Slop Oil/Produced water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.

Condition 15.1.4 – All truck loading of Slop/Oil and Produced Water shall be done using the submerged fill method. The "submerged fill method" shall, for the purposes of this permit, mean either bottom filling or filling by extending the pipe to near the bottom of the tank and as soon as practicable, below the level of liquid.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S056	Stabilizer Heater (10.09 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Stabilizer Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

10.09 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
10.09 MMBtu		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 10.09 MMBtu	**Type and Btu/hr rating of burners:** 10.09 MMBtu

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
10,503 scf/hr
92 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	0.83	3.64
Nitrogen Oxides (NO_X)	0.99	4.33
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.08	0.33
Particulate Matter (PM_{10})	0.08	0.33
Total Particulate Matter (TSP)	0.08	0.33
Sulfur Dioxide (SO_2)	0.01	0.03
Volatile Organic Compounds (VOC)	0.05	0.24
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	7.42E-04	3.25E-03
N-Hexane	4.55E-05	1.99E-04
Benzene	2.08E-05	9.10E-05
Toluene	3.36E-05	1.47E-04
Other HAPs	1.91E-05	8.38E-05
Total HAPs	8.61E-04	3.77E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 10.09 mmBtu/hr = 0.91 lb/hr] However the unit is subject to a more stringent emission limit of 0.08 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.c.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1 and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 10.09 mmBtu/hr = 31.28 lb/hr] However the unit is subject to a more stringent emission limit of 0.01 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.c.

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 10.09 mmBtu/hr

Condition 6.1.2.c. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	0.99	4.33
CO	0.83	3.64
$PM_{2.5}$ / PM_{10} / PM(1)	0.08	0.33
SO_2	0.01	0.03
VOCs	0.05	0.24

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 10,503 scf/hr and 92 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S058	Fire Pump Engine(s)	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

One or more diesel-fired fire pump engines or emergency generators not to exceed an aggregate capacity of 3,000 hp

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
MM/DD/YYYY	June 2023	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

3,000 hp

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 3,000 hp	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel
153.9 gal/hr
15,386 gallons per rolling, 12-month period

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel	ULSD	N/A	19,300 Btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	17.26	0.86
Nitrogen Oxides (NO_X)	31.75	1.59
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.99	0.05
Particulate Matter (PM_{10})	0.99	0.05
Total Particulate Matter (TSP)	0.99	0.05
Sulfur Dioxide (SO_2)	0.03	0.002
Volatile Organic Compounds (VOC)	31.75	1.59
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Benzene	1.64E-02	8.18E-04
Total HAP	3.32E-02	1.66E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

40 CFR 60, Subpart IIII
AP-42, Section 3.4

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

R13-2896K
Condition 8.1.3 - Permittee is authorized to construct a fire pump engine/generator or multiple engines/ generators (S058) not to exceed an aggregate mechanical boilerplate rating of 3,000 hp and to be fired only by diesel. The aggregate quantity of diesel fuel that shall be consumed in the additional engines shall not exceed 153.9 gallons per hour and 15,386 gallons per rolling twelve (12) month period during non-emergency use. The aggregate emissions from the additional fire pumps shall not exceed the following limits:
NOX: 31.75 lb/hr, 1.59 tpy; CO: 17.26 lb/hr, 0.86 tpy; PM: 0.99 lb/hr, 0.05 tpy; VOC: 31.75 lb/hr, 1.59 tpy

Condition 8.1.4 - The maximum yearly hours of operation shall not exceed an annual limit of 100 hours of non-emergency use as recorded with a non-resettable hour meter.

40 CFR 60, Subpart IIII
The engines are subject to the applicable requirements of 40 CFR 60, Subpart IIII
40 CFR 60.4205(c) - comply with applicable limits in Table 4 to 40 CFR 60, Subpart IIII

40 CFR 63, Subpart ZZZZ
40 CFR 63.6590(c) - comply with 40 CFR 60, Subpart IIII

☑ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-802	Natural Gasoline Storage Tank TK-802	C001, C006

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2012	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

714,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.1 – The storage tank will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from the storage tank shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K
Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-2802	Natural Gasoline Storage Tank TK-2802	C001, C006

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2014	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

1,260,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.1 – The storage tank will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from the storage tank shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K
Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-3802	Natural Gasoline Storage Tank TK-3802	C001, C006

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

714,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or <u>construction permit</u> with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.1 – The storage tank will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from the storage tank shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K
Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-4802	Natural Gasoline Storage Tank TK-4802	C001, C006

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

1,260,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.1 – The storage tank will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from the storage tank shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K

Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-5802	Natural Gasoline Storage Tank TK-5802	C001, C006

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

714,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.1 – The storage tank will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from the storage tank shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K
Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-6802	Natural Gasoline Storage Tank TK-6802	C001, C006

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

1,260,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.1 – The storage tank will utilize a natural gas blanket to eliminate natural gasoline vapors from being emitted to atmosphere. Working and breathing losses of natural gas from the storage tank shall be collected by the VRU and sent via closed vent system to the Hot Oil Heater (S001) for use as fuel.

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;

i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K
Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-7802	Refrigerated Propane Storage Tank TK-7802	C012

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

4,200,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)		
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60.110b(a) – Applicability

40 C.F.R. § 60.112b(a)(3) and 60.113b(c) – Operating Requirements

40 C.F.R. § 60.115b(c) – Reporting & Recordkeeping Requirements

40 C.F.R. § 60.116b – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 12.1.2 – The storage tank shall utilize the VRU to recapture propane product that flashes-off from the storage tank, recondensethe product, and then route it back to the storage tank

Condition 12.1.3 – The VRU shall employ a vapor return which shall be designed to achieve a guaranteed capture efficiency of 100% for the storage tank.

Condition 12.1.4 – The storage tank is subject to the applicable requirements of 40 CFR 60, Subpart Kb including the following;

a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following: **[40 CFR §60.112b(a)]**
    3. A closed vent system and control device meeting the following specifications:
        i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b). **[40 CFR §60.112b(a)(3)(i)]**
        ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions. **[40 CFR §60.112b(a)(3)(ii)]**

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart Kb
40 C.F.R. § 60. 112b(a)(3) – Permittee shall install a closed vent system and control device meeting the following specifications;
i. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b).
ii. The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

40 C.F.R. § 60.113b(c)(1) – Permittee shall submit for approval by the Administrator an operating plan containing the following;
i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or

liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph

ii. A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

40 C.F.R. § 60.113b(c)(2) – Permittee shall operate the closed vent system and control device and monitor the parameters on both in accordance with the operating plan submitted to the Administrator in accordance with (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case the modified plan applies.

40 C.F.R. § 60.115b(c) – Permittee shall keep records of the operating plan and records of the measured values of the parameters monitored in accordance with § 60.113b(c)(2

40 C.F.R. § 60.116b(a) – Permittee shall maintain records for at least two years

40 C.F.R. § 60.116b(b) – Permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for the life of the unit

45 C.S.R. 13, Permit R13-2896K

Condition 12.2.1 – To demonstrate compliance with Condition 12.1.3, the permittee shall monitor the VRU system in accordance with the plans and specifications and manufacturer's recommendations.

Condition 12.3.1. – Permittee shall maintain accurate records of the VRU equipment inspection and/or preventative maintenance procedures

Condition 12.3.2. – Permittee shall maintain accurate records of the occurrence and duration of any malfunction or operational shutdown of the VRU during which excess emissions occur. For each such case, the following information shall be recorded;

a. The equipment involved
b. Steps taken to minimize emissions during the event
c. The duration of the event
d. The estimated increase in emissions during the event. For each such case associated with an equipment malfunction, the additional information shall also be recorded;
e. The cause of the malfunction
f. Steps taken to correct the malfunction
g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction

Condition 12.3.3. – Upon request by the Director, the Permittee shall report deviations within a requested time frame of any occurrences when the control device was operated outside of the parameters defined in the monitoring plan.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-906	Slop Tank TK-906	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

21,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
	248,712 gal/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	8.88	0.05
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.5 – The maximum annual throughput and VOC emissions for the specified tanks shall not exceed the following;

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-906	Slop Oil	248,712	0.05

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit: N/A**
TK-907	Produced Water Tank TK-907	

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

63,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
	754,824 gal/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	26.96	0.14
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.5 – The maximum annual throughput and VOC emissions for the specified tanks shall not exceed the following;

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-907	Produced Water	754,824	0.14

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit: N/A**
TK-2906	Slop Tank TK-2906	

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

21,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
	248,712 gal/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	8.88	0.05
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.5 – The maximum annual throughput and VOC emissions for the specified tanks shall not exceed the following;

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-2906	Slop Oil	248,712	0.05

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit: N/A**
TK-2907	Produced Water Tank TK-2907	

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

63,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
	754,824 gal/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	26.96	0.14
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.5 – The maximum annual throughput and VOC emissions for the specified tanks shall not exceed the following;

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-2907	Produced Water	754,824	0.14

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TK-L-1	Gasoline Dispensing Tank TK-L-1	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Aboveground storage tank

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2017	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

1,000 gal

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
	12,000 gal/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☒ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	15.71	0.13
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.5 – The maximum annual throughput and VOC emissions for the specified tanks shall not exceed the following;

Tank	Material	Throughput (gallons)	Emissions (tons)
TK-L-1	Gasoline(1)	12,000	0.13

(1) This is purchased retail gasoline, not natural gasoline as produced on site

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
L-1	Gasoline Dispensing Loading L-1	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Loading of Gasoline Dispenser; liquid transfer operation. Max fill rate of 1 gal/min.

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2017	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

12,000 gal/yr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
	12,000 gal/yr	8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☒ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired

Maximum design heat input and/or maximum horsepower rating:	**Type and Btu/hr rating of burners:**
N/A	N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Gasoline
12,000 gal/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	0.18	0.07
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane		
Benzene		
Toluene		
Other HAPs		
Total HAPs		
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-2896K
Condition 15.1.1 – The maximum design capacity of material loading/unloading and maximum emissions associated emissions shall not exceed the following:

Emission Unit ID	Material Loaded/Unloaded	Truck (gal/hr)	Rail (gpm)	Barge (gpm)	VOC Emissions (lb/hr)	VOC Emissions (ton/yr)
L-1	Gasoline Dispenser	20	No	No	0.18	0.072

Condition 15.1.2 – The maximum Slop Oil/Produced Water loaded into trucks (S015) and Gasoline Dispenser Loading (L-1) shall not exceed a maximum of 2,007,070 and 12,000 gallons per year, respectively. The maximum Natural Gasoline loaded into barges (S033) shall not exceed a maximum of 408,240,000 gallons per year.

Condition 15.1.3 – The main liquids loading area (S008, S033) shall employ vapor balance (closed system) to route all displaced vapors back to the tanks when loading propane, isobutane, butanes, natural gasoline, or NGLs to truck or railcar and when loading propane to barge. Natural gasoline barge loading (S033) operations and Slop Oil/Produced water (S015), and Gasoline Dispenser (L-1) truck loading operations are not required to use vapor balance.

Condition 15.1.4 – All truck loading of Slop/Oil and Produced Water shall be down using the submerged fill method. The "submerged fill method" shall, for the purposes of this permit, mean either bottom filling or filling by extending the pipe to near the bottom of the tank and as soon as practicable, below the level of liquid.

____ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-2896K
Condition 15.2.1 – To demonstrate compliance with Conditions 15.1.2. and 15.1.5, the permittee shall maintain a monthly record of the amount of liquids handled in the Liquids Loading and Unloading areas and in the specified storage tank

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 1	FUG AREA 1	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 1 is comprised of Cryo 1 excluding Demethanizer 1 and Cryo 2

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2011	2018

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	3.31	14.50
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O		
N-Hexane	1.13E-02	4.95E-02
Benzene	2.25E-04	9.86E-04
Toluene	3.14E-04	1.38E-03
Other HAPs		
Total HAPs	1.20E-02	5.24E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 2	FUG AREA 2	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 2 is comprised of Demethanizer 1 and Frac 2

Manufacturer:	**Model number:**	**Serial number:**
Construction date:	**Installation date:** 2014	**Modification date(s):**

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	7.92	34.70
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	2.18E-04	9.54E-04
N-Hexane	2.21E-02	9.69E-02
Benzene	4.40E-04	1.93E-03
Toluene	6.14E-04	2.69E-03
Other HAPs		
Total HAPs	2.34E-02	1.03E-01
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 3	FUG AREA 3	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 3 is comprised of Cryo 3

Manufacturer:	**Model number:**	**Serial number:**
Construction date:	**Installation date:** 2018	**Modification date(s):**

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	3.10	13.56
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	9.12E-05	3.99E-04
N-Hexane	9.26E-03	4.06E-02
Benzene	1.84E-04	8.07E-04
Toluene	2.57E-04	1.13E-03
Other HAPs		
Total HAPs	9.79E-03	4.29E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 4	FUG AREA 4	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 4 is comprised of Cryo 4 and Frac 1

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019 – Cryo 4	5/24/2018 – Frac 1

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	3.91	17.12
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	1.44E-04	6.32E-04
N-Hexane	1.46E-02	6.41E-02
Benzene	2.91E-04	1.28E-03
Toluene	4.07E-04	1.78E-03
Other HAPs		
Total HAPs	1.55E-02	6.78E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 5	FUG AREA 5	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 5 is comprised of Cryo 5

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	3.10	13.56
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	9.12E-05	3.99E-04
N-Hexane	9.26E-03	4.06E-02
Benzene	1.84E-04	8.07E-04
Toluene	2.57E-04	1.13E-03
Other HAPs		
Total HAPs	9.79E-03	4.29E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 6	FUG AREA 6	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 6 is comprised of Cryo 6

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	3.10	13.56
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	9.12E-05	3.99E-04
N-Hexane	9.26E-03	4.06E-02
Benzene	1.84E-04	8.07E-04
Toluene	2.57E-04	1.13E-03
Other HAPs		
Total HAPs	9.79E-03	4.29E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FUG AREA 7	FUG AREA 7	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Fugitive Area 7 is comprised of Cryo 7

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☐ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: N/A	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)		
Nitrogen Oxides (NO_X)		
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)		
Particulate Matter (PM_{10})		
Total Particulate Matter (TSP)		
Sulfur Dioxide (SO_2)		
Volatile Organic Compounds (VOC)	3.10	13.56
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	9.12E-05	3.99E-04
N-Hexane	9.26E-03	4.06E-02
Benzene	1.84E-04	8.07E-04
Toluene	2.57E-04	1.13E-03
Other HAPs		
Total HAPs	9.79E-03	4.29E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5365a – Applicability

40 C.F.R. § 60.5400a – Standards

40 C.F.R. § 60.5401a – Exceptions

40 C.F.R. § 60.5420a – Recordkeeping

40 C.F.R. § 60.5421a – Reporting

45 C.S.R. 13, Permit R13-2896K
Condition 17.1.1 – The permittee shall operate FUG AREAS 1 – 7 in accordance with all applicable requirements given under 40 CFR 60 Subpart OOOOa.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

40 C.F.R. 60 Subpart OOOOa
40 C.F.R. § 60.5400(a) – You must comply with the requirements of §§60.482-1a(a), (b), and (d) and 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

40 C.F.R. § 60.5401a(a) – You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

40 C.F.R. § 60.5401a(b)(1) – Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400a(c), paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa.

40 C.F.R. § 60.65401a(b)(2) – If an instrument reading of 500 ppm or greater is measured, a leak is detected.

40 C.F.R. § 60.5401a(b)(3)(i) – When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

40 C.F.R. § 60.5401a(b)(3)(ii) – A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

40 C.F.R. § 60.5401a(b)(4)(i) – Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

40 C.F.R. § 60.5401a(b)(4)(ii) – No pressure relief device described in paragraph (b)(4)(i) of this section shall be allowed to operate for more than 30 days after a pressure release without monitoring

40 C.F.R. § 60.5421a(a) – You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

40 C.F.R. § 60.5421a(b) – The following recordkeeping requirements shall apply to pressure relief devices subject to the requirements of §60.5401a(b)(1) of this subpart.

1. When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.
2. When each leak is detected as specified in §60.5401a(b)(2), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:
    i. The instrument and operator identification numbers and the equipment identification number.
    ii. The date the leak was detected and the dates of each attempt to repair the leak.
    iii. Repair methods applied in each attempt to repair the leak.
    iv. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.
    v. "Repair delayed" the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
    vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
    vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.
    viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.
    ix. The date of successful repair of the leak.
    x. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) shall be signed by the owner or operator.

40 C.F.R. § 60.5422a(a) – You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b). (c)(2)(i) through (iv) and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 C.F.R. § 60.5422a(b) – An owner or operator shall include the following information in the initial semiannual report in addition to the information required in §60.487a(b) (1)-(4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

40 C.F.R. § 60.5422a(c) – An owner or operator shall include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2) (i) through (vi):

1. Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and
2. Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TB1A-4A	TB1A-4A	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Natural Gas Turbine

Manufacturer:	**Model number:**	**Serial number:**
GE	LM6000PG SPRINT	
Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	N/A

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):
482.6 MMBtu/hr (turbine) 475.1 MMBtu/hr (duct burner)

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 482.6 MMBtu/hr (turbine) 475.1 MMBtu/hr (duct burner)	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Natural Gas
487,704 scfh and 4,272 mmscf/yr (turbine)
350,110 scfh and 611 mmscf/yr (duct burner)

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.896 gr/100 ft3	N/A	1,357 Btu/ft3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	152.90	10.40
Nitrogen Oxides (NO_X)	41.86	15.13
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	3.86	16.91
Particulate Matter (PM_{10})	3.86	16.91
Total Particulate Matter (TSP)	3.86	16.91
Sulfur Dioxide (SO_2)	1.64	7.19
Volatile Organic Compounds (VOC)	4.81	1.97
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	0.03	0.14
Benzene	0.01	0.03
Toluene	0.06	0.27
Total HAPs	0.49	2.17
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Vendor guarantees and AP-42, Section 3.1.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493

Condition 4.1.2.b – fire only natural gas or ethane

Condition 4.1.2.c – operate Selective Catalytic Reduction and Oxidation Catalyst

Condition 4.1.2.d – operate according to good combustion practices

Condition 4.1.2.e – maximum emissions shall not exceed the following:

GE LM6000PG SPRINT Emission Limits

Pollutant	lbs/hour			tons/year
	Startup	Shutdown	Steady-State	
CO	152.90	95.82	2.04	10.40
NOx	41.86	41.86	3.35	15.13
Total PM	3.19	3.19	3.86	16.91
SO2	1.64	1.64	1.64	7.19
VOC	4.81	4.81	0.44	1.97
Formaldehyde	0.34	0.34	0.34	1.50
Total HAPs	0.49	0.49	0.49	2.17

Siemens SGT-800 Emission Limits

Pollutant	lbs/hour			tons/year
	Startup	Shutdown	Steady-State	
CO	51.84	12.48	0.61	10.74
NOx	25.68	20.88	3.49	20.35
Total PM	0.72	0.48	3.52	14.86
SO2	1.69	1.69	1.69	7.39
VOC	2.88	0.48	0.35	1.86
Formaldehyde	0.13	0.13	0.13	0.57
Total HAPs	0.29	0.29	0.29	1.25

Condition 4.1.2.f. –annual hours of startup and shutdown shall not exceed the following:

CT	Startup	Shutdown
GE LM6000PG SPRINT	12	12
Siemens SGT-800	256	256

Condition 4.1.2.h – power supplied to the grid must be less than 219,000 mW-hours per year

Condition 4.1.3.a – duct burners shall fire only natural gas or ethane. Heat input shall not exceed 475.1 MMBtu/hr

Condition 4.1.3.b – operate Selective Catalytic Reduction and Oxidation Catalyst when operating duct burners. Do not operate duct burners during startup or shutdown

Condition 4.1.3.c – operate duct burners according to good combustion practices

Condition 4.1.3.d – duct burner emissions shall not exceed the following:

Pollutant	lbs/hour	tons/year
CO	2.12	1.86
NOx	3.50	3.05
Total PM	3.65	3.19
SO2	0.28	0.24
VOC	0.13	0.11
Formaldehyde	0.03	0.03
Total HAPs	0.05	0.04

Condition 4.1.3.f – duct burners shall combust no more than 610.81 mmscf fuel gas per year

Condition 4.1.7.c – inject ammonia for Selective Catalytic Reduction according to manufacturer's recommendations. Ammonia slip must not exceed 5 ppmvd

Condition 4.1.7.d – operate Selective Catalytic Reduction and Oxidation Catalyst according to safety and good air pollution control practices

45 C.S.R. 2 (applicable to duct burners only)

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.a – Particulate Matter Emission Limitation – The total allowable emission rate of PM shall be the product of 0.09 and the total design heat input provided however that no more than 1200 lbs/hr of PM shall be discharged into the open air from all such units.

45 C.S.R. 10 (applicable to duct burners only)

45 CSR§10-3.1.e – SO2 Emission Limitation; The total allowable emission rate of SO2 shall be the product of 3.2 and the total design heat input in mmBtu/hr

45 CSR§10-5.1. – the concentration of hydrogen sulfide in the fuel gas must not exceed 50 grains per 100 cubic feet.

40 C.F.R. 60 Subpart KKKK

40 C.F.R. 60.4320 – NOX emissions standards

40 C.F.R. 60.4330 – SO2 emissions standards

☒ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-3493

Condition 4.1.2.g – Maintain records of the vendor's emissions guarantees for the following pollutants:

Pollutant	GE LM6000PG SPRINT		Siemens SGT-800	
	Uncontrolled (ppmvd)	Controlled (ppmvd)	Uncontrolled (ppmvd)	Controlled (ppmvd)
CO	94.0	2.0	5.0	0.5
NOx	25.0	2.0	35.0	1.8
Total PM	n/a	n/a	2.5	n/a
VOC	11.0	1.0	5.0	0.5
Formaldehyde	n/a	n/a	0.1	0.1

Condition 4.1.3.d – Maintain records of the vendor's guarantees for the following pollutants from the duct burners:

Pollutant	Requirement (ppmvd)
CO	2.0
NOx	2.0
VOC	1.0

Condition 4.1.7.b – monitor and replace the oxidation catalyst according to good engineering practices and manufacturer's recommendations

Conditions 4.2.1, 4.2.2 – maintain a visible boilerplate, product literature, or manufacturer's data documenting the maximum capacity of each unit

Condition 4.2.3 – record monthly and rolling 12-month total hours each turbine operates in startup mode and in shutdown mode.

Condition 4.2.4 – record monthly and rolling 12-month total mW exported to the power grid

Condition 4.2.5 – record monthly and rolling 12-month volumetric fuel usage in the duct burners

Condition 4.2.6 – operate a continuous emissions monitoring system measuring NOX from each turbine

Condition 4.2.7 – if required, conduct Method 9 observations to verify compliance with opacity limits

Condition 4.2.8.b – maintain a copy of the site specific maintenance plan or the manufacturer maintenance plan for the oxidation catalysts

Condition 4.3.2.a – conduct initial and periodic stack testing for NOX

Condition 4.2.2.b – conduct initial and periodic stack testing for CO

Condition 4.4.1 – maintain records of sampling ana analyses

Condition 4.4.2 – maintain records of visible emissions checks 40 C.F.R. 60 Subpart KKKK 40 C.F.R. 60.4345 – NOX CEMS monitoring requirements 40 C.F.R. 60.4360-4370 – sulfur content monitoring requirements 40 C.F.R. 60.4375 – reporting requirements 40 C.F.R. 60.4405 – NOX testing requirements when using NOX CEMS 40 C.F.R. 60.4415 – sulfur content testing requirements
Are you in compliance with all applicable requirements for this emission unit? ☒Yes ☐No **If no, complete the Schedule of Compliance Form as ATTACHMENT F.**

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
TB1B-4B	TB1B-4B	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Natural Gas Turbine

Manufacturer:	**Model number:**	**Serial number:**
Siemens	SGT-800	
Construction date:	**Installation date:**	**Modification date(s):**
TBD	TBD	N/A

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):
496.2 MMBtu/hr (turbine) 475.1 MMBtu/hr (duct burner)

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 496.2 MMBtu/hr (turbine) 475.1 MMBtu/hr (duct burner)	**Type and Btu/hr rating of burners:** N/A

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.
Natural Gas
365,684 scfh and 3,203 mmscf/yr (turbine)
350,110 scfh and 611 mmscf/yr (duct burner)

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	0.896 gr/100 ft3	N/A	1,357 Btu/ft3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	51.84	10.74
Nitrogen Oxides (NO_X)	25.68	20.35
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	3.52	14.86
Particulate Matter (PM_{10})	3.52	14.86
Total Particulate Matter (TSP)	3.52	14.86
Sulfur Dioxide (SO_2)	1.69	7.39
Volatile Organic Compounds (VOC)	2.88	1.86
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Xylene	0.03	0.14
Benzene	0.01	0.03
Toluene	0.06	0.28
Total HAPs	0.29	1.25
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

Vendor guarantees and AP-42, Section 3.1.

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 13, Permit R13-3493

Condition 4.1.2.b – fire only natural gas or ethane

Condition 4.1.2.c – operate Selective Catalytic Reduction and Oxidation Catalyst

Condition 4.1.2.d – operate according to good combustion practices

Condition 4.1.2.e – maximum emissions shall not exceed the following:

GE LM6000PG SPRINT Emission Limits

Pollutant	lbs/hour			tons/year
	Startup	Shutdown	Steady-State	
CO	152.90	95.82	2.04	10.40
NOx	41.86	41.86	3.35	15.13
Total PM	3.19	3.19	3.86	16.91
SO2	1.64	1.64	1.64	7.19
VOC	4.81	4.81	0.44	1.97
Formaldehyde	0.34	0.34	0.34	1.50
Total HAPs	0.49	0.49	0.49	2.17

Siemens SGT-800 Emission Limits

Pollutant	lbs/hour			tons/year
	Startup	Shutdown	Steady-State	
CO	51.84	12.48	0.61	10.74
NOx	25.68	20.88	3.49	20.35
Total PM	0.72	0.48	3.52	14.86
SO2	1.69	1.69	1.69	7.39
VOC	2.88	0.48	0.35	1.86
Formaldehyde	0.13	0.13	0.13	0.57
Total HAPs	0.29	0.29	0.29	1.25

Condition 4.1.2.f. –annual hours of startup and shutdown shall not exceed the following:

CT	Startup	Shutdown
GE LM6000PG SPRINT	12	12
Siemens SGT-800	256	256

Condition 4.1.2.h – power supplied to the grid must be less than 219,000 mW-hours per year

Condition 4.1.3.a – duct burners shall fire only natural gas or ethane. Heat input shall not exceed 475.1 MMBtu/hr

Condition 4.1.3.b – operate Selective Catalytic Reduction and Oxidation Catalyst when operating duct burners. Do not operate duct burners during startup or shutdown

Condition 4.1.3.c – operate duct burners according to good combustion practices

Condition 4.1.3.d – duct burner emissions shall not exceed the following:

Pollutant	lbs/hour	tons/year
CO	2.12	1.86
NOx	3.50	3.05
Total PM	3.65	3.19
SO2	0.28	0.24
VOC	0.13	0.11
Formaldehyde	0.03	0.03
Total HAPs	0.05	0.04

Condition 4.1.3.f – duct burners shall combust no more than 610.81 mmscf fuel gas per year

Condition 4.1.7.c – inject ammonia for Selective Catalytic Reduction according to manufacturer's recommendations. Ammonia slip must not exceed 5 ppmvd

Condition 4.1.7.d – operate Selective Catalytic Reduction and Oxidation Catalyst according to safety and good air pollution control practices

45 C.S.R. 2 (applicable to duct burners only)

45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.a – Particulate Matter Emission Limitation – The total allowable emission rate of PM shall be the product of 0.09 and the total design heat input provided however that no more than 1200 lbs/hr of PM shall be discharged into the open air from all such units.

45 C.S.R. 10 (applicable to duct burners only)

45 CSR§10-3.1.e – SO2 Emission Limitation; The total allowable emission rate of SO2 shall be the product of 3.2 and the total design heat input in mmBtu/hr

45 CSR§10-5.1. – the concentration of hydrogen sulfide in the fuel gas must not exceed 50 grains per 100 cubic feet.

40 C.F.R. 60 Subpart KKKK

40 C.F.R. 60.4320 – NOX emissions standards

40 C.F.R. 60.4330 – SO2 emissions standards

☒ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 13, Permit R13-3493

Condition 4.1.2.g – Maintain records of the vendor's emissions guarantees for the following pollutants:

Pollutant	GE LM6000PG SPRINT		Siemens SGT-800	
	Uncontrolled (ppmvd)	Controlled (ppmvd)	Uncontrolled (ppmvd)	Controlled (ppmvd)
CO	94.0	2.0	5.0	0.5
NOx	25.0	2.0	35.0	1.8
Total PM	n/a	n/a	2.5	n/a
VOC	11.0	1.0	5.0	0.5
Formaldehyde	n/a	n/a	0.1	0.1

Condition 4.1.3.d – Maintain records of the vendor's guarantees for the following pollutants from the duct burners:

Pollutant	Requirement (ppmvd)
CO	2.0
NOx	2.0
VOC	1.0

Condition 4.1.7.b – monitor and replace the oxidation catalyst according to good engineering practices and manufacturer's recommendations

Conditions 4.2.1, 4.2.2 – maintain a visible boilerplate, product literature, or manufacturer's data documenting the maximum capacity of each unit

Condition 4.2.3 – record monthly and rolling 12-month total hours each turbine operates in startup mode and in shutdown mode.

Condition 4.2.4 – record monthly and rolling 12-month total mW exported to the power grid

Condition 4.2.5 – record monthly and rolling 12-month volumetric fuel usage in the duct burners

Condition 4.2.6 – operate a continuous emissions monitoring system measuring NOX from each turbine

Condition 4.2.7 – if required, conduct Method 9 observations to verify compliance with opacity limits

Condition 4.2.8.b – maintain a copy of the site specific maintenance plan or the manufacturer maintenance plan for the oxidation catalysts

Condition 4.3.2.a – conduct initial and periodic stack testing for NOX

Condition 4.2.2.b – conduct initial and periodic stack testing for CO

Condition 4.4.1 – maintain records of sampling ana analyses

Condition 4.4.2 – maintain records of visible emissions checks 40 C.F.R. 60 Subpart KKKK 40 C.F.R. 60.4345 – NOX CEMS monitoring requirements 40 C.F.R. 60.4360-4370 – sulfur content monitoring requirements 40 C.F.R. 60.4375 – reporting requirements 40 C.F.R. 60.4405 – NOX testing requirements when using NOX CEMS 40 C.F.R. 60.4415 – sulfur content testing requirements
Are you in compliance with all applicable requirements for this emission unit? ☒Yes ☐No **If no, complete the Schedule of Compliance Form as ATTACHMENT F.**

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
S041	Cryo HMO Heater (54.67 MMBtu/hr)	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

Cryo HMO Heater, Indirect heat exchanger

Manufacturer:	**Model number:**	**Serial number:**
Heatec, Inc.		
Construction date:	**Installation date:**	**Modification date(s):**
	2019	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

54.67 MMBtu/hr

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**
		8,760

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☒ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 54.67 MMBtu/hr	**Type and Btu/hr rating of burners:** 54.67 MMBtu/hr

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Natural Gas
56,908 scf/hr
499 MMscf/yr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Natural Gas	Negligible	N/A	961 BTU/ft^3

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	4.50	19.72
Nitrogen Oxides (NO_X)	5.36	23.48
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.41	1.78
Particulate Matter (PM_{10})	0.41	1.78
Total Particulate Matter (TSP)	0.41	1.78
Sulfur Dioxide (SO_2)	0.04	0.17
Volatile Organic Compounds (VOC)	0.29	1.29
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
CH2O	4.02E-03	1.76E-02
N-Hexane	2.47E-04	1.08E-03
Benzene	1.13E-04	4.93E-04
Toluene	1.82E-04	7.98E-04
Other HAPs	1.04E-04	4.54E-04
Total HAPs	4.66E-03	2.04E-02
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

AP-42 Section 1.4 – Natural Gas Combustion

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

45 C.S.R. 2
45 CSR§2-3.1. – Opacity Limit; shall not exceed ten (10) percent opacity

45 CSR§2-4.1.2 – Particulate Matter Emission Limitation – The total allowable emission rate of PM for a type 'b' fuel burning unit shall be the product of 0.09 and the total design heat input for such units provided however that no more than 600 lbs/hr of PM shall be discharged into the open air from all such units. [0.09 x 54.67 mmBtu/hr = 4.92 lb/hr] However the unit is subject to a more stringent emission limit of 0.41 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.b.

45 CSR§2.6 – Units constructed after October 1, 1974 shall be registered with the Director

45 CSR§2.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 [XIX] and 30 of Title 45.

45 CSR§2.8.4.2 – Exemptions; Units which combust natural gas shall be exempt from the requirements of subdivision 8.1.1 and subsection 8.2.

45 C.S.R. 10
45 CSR§10-3.1.5 – SO_2 Emission Limitation; The total allowable emission rate of SO_2 for the type 'b' fuel burning unit located in a Priority 1 Region shall be the product of 3.1 and the total design heat input discharging through the stack in mmBtu/hr [3.1 x 54.67 mmBtu/hr = 169.48 lb/hr] However the unit is subject to a more stringent emission limit of 0.04 lb/hr as specified in 45 CSR 13, Permit R13-2896K, Condition 6.1.2.b.

45 CSR§10.7 – Unit shall be permitted in accordance with W. Va. Code 22-5-1 et seq., and Series 13, 14, 19 and 30 of Title 45.

45 CSR§10.10.3 – Exemptions; Units which combust natural gas shall be exempt from the requirements of section 8.

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.40c(a) – Applicability

40 C.F.R. § 60.48c – Monitoring Requirements

45 C.S.R. 13, Permit R13-2896K
Condition 6.1.1 – MDHI for the unit shall not exceed 54.67 mmBtu/hr

Condition 6.1.2.b. – Maximum emissions from the unit shall not exceed;

Pollutant	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (ton/yr)
NOx	5.36	23.48
CO	4.50	19.72
$PM_{2.5}$ / PM_{10} / PM(1)	0.41	1.78
SO_2	0.04	0.17
VOCs	0.29	1.29

(1) Includes condensables

Condition 6.1.3 – To demonstrate compliance with Condition 6.1.2, the quantity of natural gas consumed shall not exceed 56,908 scf/hr and 499 x 10^6 scf/yr.

Condition 6.1.4.a – No person shall cause, suffer, allow, or permit emission of smoke and/or particulate matter into the open air form any fuel burning unit which is greater than ten (10) percent opacity based on a six minute average **[45CSR§2-3.1]**

Condition 6.1.4.b – Permittee shall not cause, suffer, allow, or permit the discharge of PM into the open air form any fuel burning unit, measured in terms of lbs/hr in excess of the product of 0.09 and the total DHI for the fuel burning unit in mmBTU/hr,

provided that no more than 1200 lbs/hr of PM shall be discharged into the open air. **[45CSR§2-4.1]**

Condition 6.1.5. – The unit is subject to all applicable provisions of 40 CFR 60, Subpart Dc, provided that compliance with any more stringent limitation set forth under this permit shall also be demonstrated.

_X_ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

45 C.S.R. 2
45 CSR§2-3.2. – Compliance shall be determined using Method 9

45 CSR§2-8.3.3 – Owner/operators shall maintain records of the operating schedule and quantity and quality of fuel consumed. Such records are to be maintained onsite and made available to the Director or his duly authorized representative upon request.

45 CSR§2-9.3.1 – SSM excess opacity periods < 30 min and <= 40% may be reported on a quarterly basis unless otherwise required by the Director

40 C.F.R. 60 Subpart Dc
40 C.F.R. § 60.48c(a) – Permittee shall submit notification of the date of construction, reconstruction, or actual startup

40 C.F.R. § 60.48c(g)(1) – Record and maintain records of the amount of each fuel combusted during each operating day; or

40 C.F.R. § 60.48c(g)(2) – Record and maintain records of the amount of each fuel combusted during each calendar month; or

40 C.F.R. § 60.48c(g)(3) – Record and maintain records of the total amount of each fuel delivered to that property during each calendar month.

40 C.F.R. § 60.48c(i) – Maintain records for 2 years.

45 C.S.R. 13, Permit R13-2896K

Condition 6.2.1. – Permittee shall conduct Method 9 emissions observations in accordance with 40 CFR 60 Appendix A for the purpose of demonstrating compliance with Condition 6.1.4 at such reasonable times the Secretary may designate.

Condition 6.3.1. – Compliance with VE requirements of 6.1.4 shall be determined in accordance with 40 CFR 60 Appendix A, Method 9, or by using measurements from continuous opacity monitoring systems approved by the Director. **[45CSR§2-3.2]**

Condition 6.4.1 – To demonstrate compliance with Conditions 6.1.1 through 6.1.3, the permittee shall monitor and record the monthly and 12 month rolling total of the amount for natural gas consumed by the unit,

Condition 6.4.2 – The permittee shall maintain records of all monitoring data required by Condition 6.2.1.

Condition 6.5.1 – Any deviation from the allowable VE requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 shall be reported in writing to the Director as soon as practicable but in any case within ten (10) calendar days of the occurrence.

Are you in compliance with all applicable requirements for this emission unit? _X_ Yes ___No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
EG1	Emergency Generator	N/A

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

1676 hp diesel fired emergency generator engine

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
	TBD	

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

1676 hp

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☒ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 1676 hp	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Fuel Oil #2 - 69.4 gal/hr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Fuel Oil	ULSD	N/A	19,300 Btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	12.13	0.61
Nitrogen Oxides (NO_X)	16.45	0.82
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.77	0.04
Particulate Matter (PM_{10})	0.77	0.04
Total Particulate Matter (TSP)	0.77	0.04
Sulfur Dioxide (SO_2)	3.43	0.17
Volatile Organic Compounds (VOC)	5.60	0.28
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Formaldehyde	0.01	6.92E-04
Total HAPs	0.05	2.27E-03
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

40 CFR 60, Subpart IIII
AP-42, Section 3.4

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

R13-3493
Condition 4.1.5 - Permittee is authorized to construct an Emergency Generator shall not exceed 1,676 hp, shall be fired only with diesel fuel with a maximum sulfur content not to exceed 0.05%, and shall not operate in excess of 100 hours per year during times not defined as emergencies.. The maximum emissions shall not exeed NOX: 16.45 lb/hr, 0.82 tpy; CO: 12.13 lb/hr, 0.61 tpy; PM: 0.77 lb/hr, 0.04 tpy; VOC: 5.60 lb/hr, 0.28 tpy; HAPs 0.01 lb/hr, 0.01 tpy

40 CFR 60, Subpart IIII
The engines are subject to the applicable requirements of 40 CFR 60, Subpart IIII
40 CFR 60.4205(c) - comply with applicable limits in Table 4 to 40 CFR 60, Subpart IIII

40 CFR 63, Subpart ZZZZ
40 CFR 63.6590(c) - comply with 40 CFR 60, Subpart IIII

☑ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT E - Emission Unit Form

Emission Unit Description

Emission unit ID number:	**Emission unit name:**	**List any control devices associated with this emission unit:**
FP1	Emergency Fire Pump Engine	None

Provide a description of the emission unit (type, method of operation, design parameters, etc.; for engines, please indicate compression or spark ignition, lean or rich, four or two stroke, non-emergency or emergency, certified or not certified, as applicable)

700 hp

Manufacturer:	**Model number:**	**Serial number:**

Construction date:	**Installation date:**	**Modification date(s):**
MM/DD/YYYY	TBD	MM/DD/YYYY

Design Capacity (examples: furnaces - tons/hr, tanks – gallons, boilers – MMBtu/hr, engines - hp):

700 hp

Maximum Hourly Throughput:	**Maximum Annual Throughput:**	**Maximum Operating Schedule:**

Fuel Usage Data **(fill out all applicable fields)**

Does this emission unit combust fuel? ☑ Yes ☐ No	**If yes, is it?** ☐ Indirect Fired ☐ Direct Fired
Maximum design heat input and/or maximum horsepower rating: 700 hp	**Type and Btu/hr rating of burners:**

List the primary fuel type(s) and if applicable, the secondary fuel type(s). For each fuel type listed, provide the maximum hourly and annual fuel usage for each.

Diesel - 35.9 gal/hr

Describe each fuel expected to be used during the term of the permit.

Fuel Type	Max. Sulfur Content	Max. Ash Content	BTU Value
Diesel	ULSD	N/A	19,300 Btu/gal

Emissions Data		
Criteria Pollutants	Potential Emissions	
	PPH	TPY
Carbon Monoxide (CO)	5.07	0.25
Nitrogen Oxides (NO_X)	4.29	0.21
Lead (Pb)		
Particulate Matter ($PM_{2.5}$)	0.32	0.02
Particulate Matter (PM_{10})	0.32	0.02
Total Particulate Matter (TSP)	0.32	0.02
Sulfur Dioxide (SO_2)	1.44	0.07
Volatile Organic Compounds (VOC)	1.46	0.07
Hazardous Air Pollutants	Potential Emissions	
	PPH	TPY
Formaldehyde	0.006	2.89E-04
Total HAP	0.02	9.49E-04
Regulated Pollutants other than Criteria and HAP	Potential Emissions	
	PPH	TPY

List the method(s) used to calculate the potential emissions (include dates of any stack tests conducted, versions of software used, source and dates of emission factors, etc.).

40 CFR 60, Subpart IIII
AP-42, Section 3.4

Applicable Requirements

List all applicable requirements for this emission unit. For each applicable requirement, include the underlying rule/regulation citation and/or construction permit with the condition number. (*Note: Title V permit condition numbers alone are not the underlying applicable requirements*). If an emission limit is calculated based on the type of source and design capacity or if a standard is based on a design parameter, this information should also be included.

R13-3493
Condition 4.1.5 - Permittee is authorized to construct an emergency fire pump that shall not exceed 700 hp, shall be fired only with diesel fuel with a maximum sulfur content not to exceed 0.05%, and shall not operate in excess of 100 hours per year during times not defined as emergencies. The maximum emissions shall not exeed NOX: 4.29 lb/hr, 0.21 tpy; CO: 5.07 lb/hr, 0.25 tpy; PM: 0.32 lb/hr, 0.02 tpy; VOC: 1.46 lb/hr, 0.07 tpy; HAPs 0.01 lb/hr, 0.01 tpy

40 CFR 60, Subpart IIII
The engines are subject to the applicable requirements of 40 CFR 60, Subpart IIII
40 CFR 60.4205(c) - comply with applicable limits in Table 4 to 40 CFR 60, Subpart IIII

40 CFR 63, Subpart ZZZZ
40 CFR 63.6590(c) - comply with 40 CFR 60, Subpart IIII

☑ Permit Shield

For all applicable requirements listed above, provide monitoring/testing/recordkeeping/reporting which shall be used to demonstrate compliance. If the method is based on a permit or rule, include the condition number or citation. (Note: Each requirement listed above must have an associated method of demonstrating compliance. If there is not already a required method in place, then a method must be proposed.)

Are you in compliance with all applicable requirements for this emission unit? ☑ Yes ☐ No

If no, complete the **Schedule of Compliance Form** as **ATTACHMENT F**.

ATTACHMENT G: AIR POLLUTION CONTROL DEVICE FORMS

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:	**List all emission units associated with this control device.**	
C004A	S004A – Ground Flare	
Manufacturer:	**Model number:**	**Installation date:** MM/DD/YYYY
Callidus	CAL-MP	2015

Type of Air Pollution Control Device:

☐ Baghouse/Fabric Filter	☐ Venturi Scrubber	☐ Multiclone
☐ Carbon Bed Absorber	☐ Packed Tower Scrubber	☐ Single Cyclone
☐ Carbon Drum(s)	☐ Other Wet Scrubber	☐ Cyclone Bank
☐ Catalytic Incinerator	☐ Condenser	☐ Settling Chamber
☐ Thermal Incinerator	☒ Flare	☐ Other (describe) _____
☐ Wet Plate Electrostatic Precipitator		☐ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
Volatile Organic Compounds (VOC)	100%	98%
Total HAPs	100%	98%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Design Capacity – 22,500 mmBtu/hr

Maximum Flow Rate – 19,800,000 scf/hr / 173,448 mmscf/yr

Is this device subject to the CAM requirements of 40 C.F.R. 64? X Yes _ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Flare shall be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Flare shall be operated with a flame present at all times except during SSM.

The pilot light shall be continuously monitored and recorded.

Flare shall be designed to meet the Btu and exit velocity requirements in accordance with 60.18.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:	**List all emission units associated with this control device.**	
C034	S034 – Pigging (Ground Flare)	
Manufacturer:	**Model number:**	**Installation date:** MM/DD/YYYY 2017

Type of Air Pollution Control Device:

☐ Baghouse/Fabric Filter	☐ Venturi Scrubber	☐ Multiclone
☐ Carbon Bed Absorber	☐ Packed Tower Scrubber	☐ Single Cyclone
☐ Carbon Drum(s)	☐ Other Wet Scrubber	☐ Cyclone Bank
☐ Catalytic Incinerator	☐ Condenser	☐ Settling Chamber
☐ Thermal Incinerator	☒ Flare	☐ Other (describe) _____
☐ Wet Plate Electrostatic Precipitator		☐ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
Volatile Organic Compounds (VOC)	100%	98%
Total HAPs	100%	98%

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

Design Capacity – 170.71 mmBtu/hr

Maximum Flow Rate – 72,000 scf/hr / 864,000 scf/yr

Is this device subject to the CAM requirements of 40 C.F.R. 64? _ Yes X No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Uncontrolled emissions < 100 tpy for VOC

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Flare shall be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Flare shall be operated with a flame present at all times except during SSM.

The pilot flame shall be continuously monitored and recorded.

Flare shall be designed to meet the Btu and exit velocity requirements in accordance with 60.18.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:	**List all emission units associated with this control device.**	
SCR1-4	TB1A,TB2A, TB3A, TB4A, TB1B, TB2B, TB3B, TB4B and associated duct burners	
Manufacturer: TBD	**Model number:** TBD	**Installation date:** TBD

Type of Air Pollution Control Device:

☐ Baghouse/Fabric Filter	☐ Venturi Scrubber	☐ Multiclone
☐ Carbon Bed Absorber	☐ Packed Tower Scrubber	☐ Single Cyclone
☐ Carbon Drum(s)	☐ Other Wet Scrubber	☐ Cyclone Bank
☐ Catalytic Incinerator	☐ Condenser	☐ Settling Chamber
☐ Thermal Incinerator	☐ Flare	☒ Other (describe) Selective Catalytic Reduction
☐ Wet Plate Electrostatic Precipitator		☐ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
NOx	100	92% - 95% depending on operating Scenario A or B

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

34.3 lbs ammonia per hour.

Is this device subject to the CAM requirements of 40 C.F.R. 64? X Yes _ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

NOX CEMS and periodic performance testing.

ATTACHMENT G - Air Pollution Control Device Form

Control device ID number:	**List all emission units associated with this control device.**	
OC1	TB1A,TB2A, TB3A, TB4A, TB1B, TB2B, TB3B, TB4B and associated duct burners	
Manufacturer: TBD	**Model number:** TBD	**Installation date:** TBD

Type of Air Pollution Control Device:

☐ Baghouse/Fabric Filter	☐ Venturi Scrubber	☐ Multiclone
☐ Carbon Bed Absorber	☐ Packed Tower Scrubber	☐ Single Cyclone
☐ Carbon Drum(s)	☐ Other Wet Scrubber	☐ Cyclone Bank
☐ Catalytic Incinerator	☐ Condenser	☐ Settling Chamber
☐ Thermal Incinerator	☐ Flare	☒ Other (describe) Oxidation catalyst
☐ Wet Plate Electrostatic Precipitator		☐ Dry Plate Electrostatic Precipitator

List the pollutants for which this device is intended to control and the capture and control efficiencies.

Pollutant	Capture Efficiency	Control Efficiency
CO	100	90% -98% depending on operating Scenario A or B
VOC	100	90%-91%, depending on operating Scenario A or B

Explain the characteristic design parameters of this control device (flow rates, pressure drops, number of bags, size, temperatures, etc.).

TBD

Is this device subject to the CAM requirements of 40 C.F.R. 64? _X Yes _ No

If Yes, **Complete ATTACHMENT H**

If No**, Provide justification.**

Describe the parameters monitored and/or methods used to indicate performance of this control device.

Periodic performance testing, inspection, and maintenance per manufacturer's recommendations, continuous monitoring of catalyst bed inlet temperature.

ATTACHMENT H: COMPLIANCE ASSURANCE MONITORING (CAM) PLAN

ATTACHMENT H - Compliance Assurance Monitoring (CAM) Plan Form

For definitions and information about the CAM rule, please refer to 40 CFR Part 64. Additional information (including guidance documents) may also be found at http://www.epa.gov/ttn/emc/cam.html

CAM APPLICABILITY DETERMINATION

1) Does the facility have a PSEU (Pollutant-Specific Emissions Unit considered separately with respect to **EACH** regulated air pollutant) that is subject to CAM (40 CFR Part 64), which must be addressed in this CAM plan submittal? To determine applicability, a PSEU must meet **all** of the following criteria (*If No, then the remainder of this form need not be completed*): ☑ YES ☐ NO

a. The PSEU is located at a major source that is required to obtain a Title V permit;

b. The PSEU is subject to an emission limitation or standard for the applicable regulated air pollutant that is NOT exempt;

LIST OF EXEMPT EMISSION LIMITATIONS OR STANDARDS:

- NSPS (40 CFR Part 60) or NESHAP (40 CFR Parts 61 and 63) proposed after 11/15/1990.
- Stratospheric Ozone Protection Requirements.
- Acid Rain Program Requirements.
- Emission Limitations or Standards for which a WVDEP Division of Air Quality Title V permit specifies a continuous compliance determination method, as defined in 40 CFR §64.1.
- An emission cap that meets the requirements specified in 40 CFR §70.4(b)(12).

c. The PSEU uses an add-on control device (as defined in 40 CFR §64.1) to achieve compliance with an emission limitation or standard;

d. The PSEU has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than the Title V Major Source Threshold Levels; AND

e. The PSEU is NOT an exempt backup utility power emissions unit that is municipally-owned.

BASIS OF CAM SUBMITTAL

2) Mark the appropriate box below as to why this CAM plan is being submitted as part of an application for a Title V permit:

☑ RENEWAL APPLICATION. **ALL** PSEUs for which a CAM plan has NOT yet been approved need to be addressed in this CAM plan submittal.

☐ INITIAL APPLICATION (submitted after 4/20/98). **ONLY** large PSEUs (i. e., PSEUs with potential post- control device emissions of an applicable regulated air pollutant that are equal to or greater than Major Source Threshold Levels) need to be addressed in this CAM plan submittal.

☐ SIGNIFICANT MODIFICATION TO LARGE PSEUs. **ONLY** large PSEUs being modified after 4/20/98 need to be addressed in this cam plan submittal. For large PSEUs with an approved CAM plan, Only address the appropriate monitoring requirements affected by the significant modification.

3) [a] BACKGROUND DATA AND INFORMATION					
Complete the following table for **all** PSEUs that need to be addressed in this CAM plan submittal. This section is to be used to provide background data and information for each PSEU In order to supplement the submittal requirements specified in 40 CFR §64.4. If additional space is needed, attach and label accordingly.					
PSEU DESIGNATION	DESCRIPTION	POLLUTANT	CONTROL DEVICE	[b] EMISSION LIMITATION or STANDARD	[c] MONITORING REQUIREMENT
S004A	Ground Flare System	VOC	C004A	45CSR13, R13-2896K, Condition 13.1.2.b; VOC 10,153 lb/hr, 39.38 tpy	The presence of a pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
TB1A/B, TB2A/B, TB3A/B, TB4A/B	Combustion turbines and associated duct burners	NO_X	Selective catalytic reduction (SCR)	Turbine: 45CSR13, R13-3493, Condition 4.1.2.e; NO_X 3.35 lb/hr & 15.13 tpy LM6000PG; 3.49 lb/hr & 20.35 tpy SGT-800 45CSR13, R13-3493, Condition 4.1.2.g.; LM6000PG NO_X 2 ppmvd @ 15% O_2; SGT-800 NO_X 1.8 ppmvd @ 15% O_2 45CSR13, R13-3493, Condition 4.1.2.i.(1)(ii) & 40 CFR 60, Subpart KKKK; NO_X 25 ppmvd @15 % O_2 or 150 ng/J of useful output (1.2 lb/MWh). Duct burner: 45CSR13, R13-3493, Condition 4.1.3.d; NO_X 3.50 lb/hr & 3.05 tpy 45CSR13, R13-3493, Condition 4.1.3.e; 2 ppmvd @ 15% O2	NO_X emissions shall be measured using a Continuous Emissions Monitoring System (CEMS) that shall be installed, maintained, and operated in accordance with 40 CFR 60 Subpart KKKK.
TB1A/B, TB2A/B, TB3A/B, TB4A/B	Combustion turbines and associated duct burners	CO	Oxidation catalyst	Turbine: 45CSR13, R13-3493, Condition 4.1.2.e.; CO 2.40 lb/hr & 10.40 tpy LM6000PG; 0.61 lb/hr & 10.74 tpy SGT-800 45CSR13, R13-3493, Condition 4.1.2.g.; LM6000PG CO 2 ppmvd @ 15% O2; SGT-800 CO 0.5 ppmvd @15% O2 Duct burner: 45CSR13, R13-3493, Condition 4.1.3.d; 2.12 lb/hr & CO 1.86 tpy 45CSR13, R13-3493, Condition 4.1.3.e; 2 ppmvd @15% O2	Regularly inspect, maintain and/or replace catalytic reduction devices in accordance with manufacturer emissions related recommendations or a site -specific plan.
EXAMPLE Boiler No. 1	Wood-Fired Boiler	PM	Multiclone	45CSR§2-4.1.c.; 9.0 lb/hr	Monitor pressure drop across multiclone: Weekly inspection of multiclone

[a] If a control device is common to more than one PSEU, one monitoring plan may be submitted for the control device with the affected PSEUs identified and any conditions that must be maintained or monitored in accordance with 40 CFR §64.3(a). If a single PSEU is controlled by more than one control device similar in design and operation, one monitoring plan for the applicable control devices may be submitted with the applicable control devices identified and any conditions that must be maintained or monitored in accordance with 40 CFR §64.3(a).

[b] Indicate the emission limitation or standard for any applicable requirement that constitutes an emission limitation, emission standard, or standard of performance (as defined in 40 CFR §64.1).

[c] Indicate the monitoring requirements for the PSEU that are required by an applicable regulation or permit condition

CAM MONITORING APPROACH CRITERIA

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.

4a) PSEU Designation:	**4b) Pollutant:**	**4c) [a] Indicator No. 1:**	**4d) [a] Indicator No. 2:**
TB1A/B, TB2A/B, TB3A/B, TB4A/B	CO	Outlet CO concentration	Catalyst bed inlet temperature
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		An initial performance test, with subsequent annual stack testing. (no more than 14 months following the previous test) unless the previous results demonstrate that the affected units achieved compliance of less than or equal to 75 percent of the applicable emission limits, then the permittee may reduce the frequency of subsequent tests to once every two years (no more than 26 calendar months following the previous test).	Temperature is continuously monitored using a thermocouple.
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		An excursion occurs if the performance testing shows CO emissions greater than 2 ppmvd @ 15% O_2 for LM6000PG or 0.5 ppmvd @ 15 % O_2 for SGT-800.	Until the first performance test, an excursion is defined as 24-hour average inlet temperature outside the manufacturer's recommended range. After the first performance test, an excursion is defined as a 24-hour average inlet temperature outside the range established during the most recent performance test. Excursions trigger an investigation, corrective action, and a reporting requirement.
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		Measurement of outlet CO emissions in accordance with 40 CFR 60, Appendix A, Method 10B	A thermocouple will be installed to measure catalyst inlet temperature. This information will be recorded in the facility's data acquisition system.
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		N/A	The thermocouple will be installed according to the manufacturer's recommendations.
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		In accordance 40 CFR 60, Appendix A, Method 10B	The thermocouple will be calibrated according to the manufacturer's recommendations.
[d] Provide the MONITORING FREQUENCY:		In accordance with 40 CFR 60, Appendix A, Method 10B	At least once per 24-hour period of operation
Provide the DATA COLLECTION PROCEDURES that will be used:		In accordance with 40 CFR 60, Appendix A, Method 10B	The temperature measurements will be recorded in the facility's data acquisition system.
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		In accordance with 40 CFR 60, Appendix A, Method 10B	If more than one temperature measurement is collected during each 24-hour period of operation, these measurements will be reduced to 24-hour block averages

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

RATIONALE AND JUSTIFICATION

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.

6a) PSEU Designation:	6b) Regulated Air Pollutant:
TB1A/B, TB2A/B, TB3A/B, TB4A/B	CO

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- Outlet CO concentration: Direct measurement of CO concentration by conducting performance testing in accordance with 40 CFR 60 Appendix A, Method 10B indicates if the CO emission limit is being met.
- Catalyst bed inlet temperature: Indicates whether the gas flowing into the catalyst bed is sufficient temperature to initiate oxidation. This is a standard monitoring approach for catalytic oxidizers in regulations proposed after November 15, 1990 (e.g., 40 CFR 63, Subpart ZZZZ).

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

- Outlet CO concentration – 2 ppmvd @15% O_2 is based on the permitted emission rate for the source.
- Catalyst bed inlet temperature – indicator range will be based on the manufacturer's recommended ranges for the catalyst inlet temperature until such time as a performance test is completed to establish a site-specific temperature range. Thermocouples will be installed no later than 180 days after commencing operation of each turbine. Testing will be performed according to the schedule provided in Item 5a) above.

CAM MONITORING APPROACH CRITERIA			
Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.			
4a) PSEU Designation: TB1A/B, TB2A/B, TB3A/B, TB4A/B	**4b) Pollutant:** NO_X	**4c) [a] Indicator No. 1:** Outlet NO_X concentration	**4d) [a] Indicator No. 2:**
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		Direct measurement of outlet NO_X concentration using a continuous emissions monitoring system (CEMS)	
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		An excursion occurs if outlet NO_X concentration is greater than 2 ppmvd @15% O_2 for the LM6000PG unit and 1.8 ppmvd @ 15% O_2 for the SGT-800 unit.	
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		CEMS installation and certification in accordance with 40 CFR 60 Subpart KKKK	
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		CEMS installation and certification in accordance with 40 CFR 60 Subpart KKKK	
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		CEMS QA/QC in accordance with 40 CFR 60 Subpart KKKK	
[d] Provide the MONITORING FREQUENCY:		CEMS monitoring frequency in accordance with 40 CFR 60 Subpart KKKK	
Provide the DATA COLLECTION PROCEDURES that will be used:		CEMS data collection in accordance with 40 CFR 60 Subpart KKKK	
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		CEMS data averaging period in accordance with 40 CFR 60 Subpart KKKK	

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

RATIONALE AND JUSTIFICATION

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.

6a) PSEU Designation:	6b) Regulated Air Pollutant:
TB1A/B, TB2A/B, TB3A/B, TB4A/B	NO_X

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- Direct measurement of outlet NO_X concentration using CEMS in accordance with 40 CFR 60, Subpart KKKK is considered presumptively acceptable monitoring pursuant to 40 CFR 64.4(b)(2) and 40 CFR 64.3(d)(2)(ii)

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

- Outlet NO_X concentration – 2 ppmvd @15% O_2 for the LM6000PG unit and 1.8 ppmvd @ 15% O_2 for the SGT-800 unit based on the permitted emission rates for the source.

CAM MONITORING APPROACH CRITERIA			
Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide monitoring data and information for EACH indicator selected for EACH PSEU in order to meet the monitoring design criteria specified in 40 CFR §64.3 and §64.4. if more than two indicators are being selected for a PSEU or if additional space is needed, attach and label accordingly with the appropriate PSEU designation, pollutant, and indicator numbers.			
4a) PSEU Designation: S004A	**4b) Pollutant:** VOC	**4c) [a] Indicator No. 1:** Presence of the pilot light flame	**4d) [a] Indicator No. 2:**
5a) GENERAL CRITERIA Describe the MONITORING APPROACH used to measure the indicators:		A duplex thermocouple or equivalent device is utilized to continuously monitor the presence of a pilot light.	
[b] Establish the appropriate INDICATOR RANGE or the procedures for establishing the indicator range which provides a reasonable assurance of compliance:		An excursion is defined as the absence of a pilot light as reported by the duplex thermocouple or equivalent device.	
5b) PERFORMANCE CRITERIA Provide the SPECIFICATIONS FOR OBTAINING REPRESENTATIVE DATA, such as detector location, installation specifications, and minimum acceptable accuracy:		A duplex thermocouple or equivalent device has been installed to monitor the presence of the pilot flame. The presence or absence of the pilot light flame is continuously monitored and recorded in the facility's data acquisition system.	
[c] For new or modified monitoring equipment, provide VERIFICATION PROCEDURES, including manufacturer's recommendations, TO CONFIRM THE OPERATIONAL STATUS of the monitoring:		An alarm will alert facility personnel that the pilot light has been extinguished. Upon confirmation that flare pilots have been extinguished, facility personnel will re-ignite the pilots. If facility personnel are unable to re-ignite the flare pilots, management personnel will attempt to implement further corrective actions or will recommend a process unit shutdown.	
Provide QUALITY ASSURANCE AND QUALITY CONTROL (QA/QC) PRACTICES that are adequate to ensure the continuing validity of the data, (i.e., daily calibrations, visual inspections, routine maintenance, RATA, etc.):		A camera mounted near the flare and redundant information helps to validate data coming from the ground flare HMI. If facility personnel are unable to verify the validity of the data, management personnel will attempt to implement further corrective actions or will recommend a process unit shutdown.	
[d] Provide the MONITORING FREQUENCY:		The monitoring device continuously records the presence or absence of the pilot light flame in the facility's data acquisition system.	
Provide the DATA COLLECTION PROCEDURES that will be used:		For the purposes of CAM, continuous records will be considered to be a single reading in each fifteen (15)-minute period.	
Provide the DATA AVERAGING PERIOD for the purpose of determining whether an excursion or exceedance has occurred:		None.	

[a] Describe all indicators to be monitored which satisfies 40 CFR §64.3(a). Indicators of emission control performance for the control device and associated capture system may include measured or predicted emissions (including visible emissions or opacity), process and control device operating parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities.

[b] Indicator Ranges may be based on a single maximum or minimum value or at multiple levels that are relevant to distinctly different operating conditions, expressed as a function of process variables, expressed as maintaining the applicable indicator in a particular operational status or designated condition, or established as interdependent between more than one indicator. For CEMS, COMS, or PEMS, include the most recent certification test for the monitor.

[c] The verification for operational status should include procedures for installation, calibration, and operation of the monitoring equipment, conducted in accordance with the manufacturer's recommendations, necessary to confirm the monitoring equipment is operational prior to the commencement of the required monitoring.

[d] Emission units with post-control PTE ≥ 100 percent of the amount classifying the source as a major source (i.e., Large PSEU) must collect four or more values per hour to be averaged. A reduced data collection frequency may be approved in limited circumstances. Other emission units must collect data at least once per 24 hour period.

RATIONALE AND JUSTIFICATION

Complete this section for **EACH** PSEU that needs to be addressed in this CAM plan submittal. This section may be copied as needed for each PSEU. This section is to be used to provide rationale and justification for the selection of EACH indicator and monitoring approach and EACH indicator range in order to meet the submittal requirements specified in 40 CFR §64.4.

6a) PSEU Designation:	6b) Regulated Air Pollutant:
S004A	VOC

7) **INDICATORS AND THE MONITORING APPROACH**: Provide the rationale and justification for the selection of the indicators and the monitoring approach used to measure the indicators. Also provide any data supporting the rationale and justification. Explain the reasons for any differences between the verification of operational status or the quality assurance and control practices proposed, and the manufacturer's recommendations. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

The presence of the pilot flame indicates that the flare is operating in such a manner as to achieve the required destruction efficiency. Therefore, Blue Racer Midstream, LLC believes that continuous verification of the presence of the flare flame pilot light provides reasonable assurance that the flare is operating properly and that the VOC emissions are in compliance with the relevant emission limits provided in Condition 13.1.2.b of permit R13- 2896K and Condition 11.1.2.b of the current Title V permit. For the purposes of CAM, continuous records will be considered to be a single reading in each 15-minute period.

8) **INDICATOR RANGES**: Provide the rationale and justification for the selection of the indicator ranges. The rationale and justification shall indicate how **EACH** indicator range was selected by either a COMPLIANCE OR PERFORMANCE TEST, a TEST PLAN AND SCHEDULE, or by ENGINEERING ASSESSMENTS. Depending on which method is being used for each indicator range, include the specific information required below for that specific indicator range. (If additional space is needed, attach and label accordingly with the appropriate PSEU designation and pollutant):

- COMPLIANCE OR PERFORMANCE TEST (Indicator ranges determined from control device operating parameter data obtained during a compliance or performance test conducted under regulatory specified conditions or under conditions representative of maximum potential emissions under anticipated operating conditions. Such data may be supplemented by engineering assessments and manufacturer's recommendations). The rationale and justification shall INCLUDE a summary of the compliance or performance test results that were used to determine the indicator range, and documentation indicating that no changes have taken place that could result in a significant change in the control system performance or the selected indicator ranges since the compliance or performance test was conducted.

- TEST PLAN AND SCHEDULE (Indicator ranges will be determined from a proposed implementation plan and schedule for installing, testing, and performing any other appropriate activities prior to use of the monitoring). The rationale and justification shall INCLUDE the proposed implementation plan and schedule that will provide for use of the monitoring as expeditiously as practicable after approval of this CAM plan, except that in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval.

- ENGINEERING ASSESSMENTS (Indicator Ranges or the procedures for establishing indicator ranges are determined from engineering assessments and other data, such as manufacturers' design criteria and historical monitoring data, because factors specific to the type of monitoring, control device, or PSEU make compliance or performance testing unnecessary). The rationale and justification shall INCLUDE documentation demonstrating that compliance testing is not required to establish the indicator range.

RATIONALE AND JUSTIFICATION:

The presence of a pilot flame indicates that the flare is operating in such a manner as to achieve the appropriate destruction efficiency. The thermocouple's or equivalent monitoring device's continuous monitoring of the presence of pilot light records this information. Any excursion will be cause for investigation and will be properly documented and reported.

APPENDIX A. PTE CALCULATIONS

TABLE N-1
SUMMARY OF SITE-WIDE AIR POLLUTANT EMISSION RATES
CLASS II ADMINISTRATIVE UPDATE
NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT
BLUE RACER MIDSTREAM, LLC

				Potential to Emit																	
				NO_X		CO		VOC		PM		PM_{10}		$PM_{2.5}$		SO_2		CO_2		CH_4		CO_2e	
Emission Unit ID	Control Device ID	Emission Point ID	Description	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)
AUTHORIZED SOURCES (UNDER CONSTRUCTION)																					
S058	N/A	P058	Fire Pump Engine(s)	31.75	1.59	17.26	0.86	31.75	1.59	0.99	0.05	0.99	0.05	0.99	0.05	0.03	0.002	--	--	--	--	--	174
S052	N/A	P052	Hot Oil Heater (61.6 MMBtu/hr)	1.48	6.47	3.63	15.91	0.33	1.45	0.46	2.01	0.46	2.01	0.46	2.01	0.04	0.19	--	--	--	--	--	31,583
S053	N/A	P053	Hot Oil Heater (61.6 MMBtu/hr)	1.48	6.47	3.63	15.91	0.33	1.45	0.46	2.01	0.46	2.01	0.46	2.01	0.04	0.19	--	--	--	--	--	31,583
S054	C011	P054	Ethane Amine Regenerator	--	--	--	--	1.98	0.43	--	--	--	--	--	--	--	--	2,790	611	0.02	0.005	2,791	611
S056	N/A	P056	Stabilizer Heater (10.09 MMBtu/hr)	0.99	4.33	0.83	3.64	0.05	0.24	0.08	0.33	0.08	0.33	0.08	0.33	0.01	0.03	--	--	--	--	--	5,175
TK-2906	N/A	TK-2906	Slop Tank TK-2906	--	--	--	--	8.88	0.05	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-2907	N/A	TK-2907	Produced Water Tank TK-2907	--	--	--	--	26.96	0.14	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-3802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-3802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-4802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-4802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-5802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-5802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-6802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-6802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-7802	C012	TK-7802	Refrigerated Propane Storage Tank TK-7802, with VRU to recapture vapors and recondense back to storage (insignificant intermittent source).	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
PLANT 5 SOURCES																					
S040	N/A	P040	Regen Gas Heater (19.28 MMBtu/hr)	1.89	8.28	1.59	6.95	0.10	0.46	0.14	0.63	0.14	0.63	0.14	0.63	0.01	0.06	--	--	--	--	--	9,888
S041	N/A	P041	Cryo HMO Heater (54.67 MMBtu/hr)	5.36	23.48	4.50	19.72	0.29	1.29	0.41	1.78	0.41	1.78	0.41	1.78	0.04	0.17	--	--	--	--	--	28,039
FUG AREA 5	N/A	FUG AREA 5	Fugitive Area 5 (Cryo 5)	--	--	--	--	3.10	13.56	--	--	--	--	--	--	--	--	--	0.14	--	9.95	--	249
PLANT 6 SOURCES																					
S044	N/A	P044	Regen Gas Heater (9.7 MMBtu/hr)	0.95	4.17	0.80	3.50	0.05	0.23	0.07	0.32	0.07	0.32	0.07	0.32	0.01	0.03	--	--	--	--	--	4,975
S045	N/A	P045	Cryo HMO Heater (26.3 MMBtu/hr)	2.58	11.29	2.17	9.49	0.14	0.62	0.20	0.86	0.20	0.86	0.20	0.86	0.02	0.08	--	--	--	--	--	13,489
FUG AREA 6	N/A	FUG AREA 6	Fugitive Area 6 (Cryo 6)	--	--	--	--	3.10	13.56	--	--	--	--	--	--	--	--	--	0.14	--	9.95	--	249
PLANT 7 SOURCES																					
S048	N/A	P048	Regen Gas Heater (9.7 MMBtu/hr)	0.95	4.17	0.80	3.50	0.05	0.23	0.07	0.32	0.07	0.32	0.07	0.32	0.01	0.03	--	--	--	--	--	4,975
S049	N/A	P049	Cryo HMO Heater (26.3 MMBtu/hr)	2.58	11.29	2.17	9.49	0.14	0.62	0.20	0.86	0.20	0.86	0.20	0.86	0.02	0.08	--	--	--	--	--	13,489
FUG AREA 7	N/A	FUG AREA 7	Fugitive Area 7 (Cryo 7)	--	--	--	--	3.10	13.56	--	--	--	--	--	--	--	--	--	0.14	--	9.95	--	249
POWER PLANT																					
PWR PLNT	N/A	Various	Power Plant Total PTE	203.17	98.92	638.94	58.40	26.93	9.17	31.31	81.09	31.31	81.09	31.31	81.09	12.750	30.83	513,659	1,458,356	9	23	514,140.00	1,459,618
EXISTING SOURCES																					
S001	N/A	P001	Hot Oil Heater (216.7 MMBtu/hr)	9.75	42.71	3.25	14.24	0.37	1.61	1.61	7.07	1.61	7.07	1.61	7.07	0.15	0.67	--	--	--	--	--	111,142
S016	N/A	P016	Hot Oil Heater (61.6 MMBtu/hr)	1.48	6.47	3.63	15.91	0.33	1.45	0.46	2.01	0.46	2.01	0.46	2.01	0.04	0.19	--	--	--	--	--	31,583
S017	N/A	P017	Hot Oil Heater (61.6 MMBtu/hr)	1.48	6.47	3.63	15.91	0.33	1.45	0.46	2.01	0.46	2.01	0.46	2.01	0.04	0.19	--	--	--	--	--	31,583
S018	N/A	P018	Hot Oil Heater (61.6 MMBtu/hr)	1.48	6.47	3.63	15.91	0.33	1.45	0.46	2.01	0.46	2.01	0.46	2.01	0.04	0.19	--	--	--	--	--	31,583
S019	N/A	P019	Hot Oil Heater (61.6 MMBtu/hr)	1.48	6.47	3.63	15.91	0.33	1.45	0.46	2.01	0.46	2.01	0.46	2.01	0.04	0.19	--	--	--	--	--	31,583
S012	N/A	P012	Regen Gas Heater (9.7 MMBtu/hr)	0.95	4.17	0.80	3.50	0.05	0.23	0.07	0.32	0.07	0.32	0.07	0.32	0.01	0.03	--	--	--	--	--	4,975
S013	N/A	P013	Cryo HMO Heater (26.3 MMBtu/hr)	2.58	11.29	2.17	9.49	0.14	0.62	0.20	0.86	0.20	0.86	0.20	0.86	0.02	0.08	--	--	--	--	--	13,489
S006	C001	P001	Glycol Dehydrator Still Vent	--	--	--	--	1.78	7.80	--	--	--	--	--	--	--	--	--	0.38	--	6.55	--	164
S004A	*C004A*	*P004A*	*Ground Flare*	*1,539.61*	*14.61*	*3,073.64*	*29.17*	*10,174.95*	*39.75*	*30.66*	*0.50*	*30.66*	*0.50*	*30.66*	*0.50*	*0.001*	*0.005*	--	--	--	--	--	*8,407*
S034	C034	P034	Flare (Pigging)	24.25	0.12	13.99	0.07	227.77	1.14	1.31	0.01	1.31	0.01	1.31	0.01	1.87	0.01	--	118.31	--	0.002	--	118
S035	*N/A*	*P035*	*Pigging Vent*	--	--	--	--	*103.10*	*0.84*	--	--	--	--	--	--	--	--	--	*0.16*	--	*13.85*	--	*346*
TK-906	N/A	TK-906	Slop Tank TK-906	--	--	--	--	8.88	0.05	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S011	N/A	P005	Ethane Amine Regenerator	--	--	--	--	1.98	8.67	--	--	--	--	--	--	--	--	2,790	12,220	0.02	0.10	2,791	12,222
TK-802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

TABLE N-1
SUMMARY OF SITE-WIDE AIR POLLUTANT EMISSION RATES
CLASS II ADMINISTRATIVE UPDATE
NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT
BLUE RACER MIDSTREAM, LLC

Emission Unit ID	Control Device ID	Emission Point ID	Description	Potential to Emit																	
				NO_X		CO		VOC		PM		PM_{10}		$PM_{2.5}$		SO_2		CO_2		CH_4		CO_2e	
				Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)
TK-2802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-2802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S008	Vapor Return to Tank	P008	Propane, i-Butane, Butanes, and Natural Gasoline Loading (Truck, Railcar, and Propane Barge)	--	--	--	--	5.99	4.21	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S055	N/A	P055	Pressurized NGL/Condensate Unloading	--	--	--	--	6.64	14.54	--	--	--	--	--	--	--	--	--	0.17	--	0.17	--	4
ROADS	N/A	ROADS	Unpaved Roads	--	--	--	--	--	--	--	43.86	--	11.69	--	1.17	--	--	--	--	--	--	--	--
FUG AREA 1	N/A	FUG AREA 1	Fugitive Area 1 (Cryo 1, Cryo 2 and Frac 1)	--	--	--	--	3.31	14.50	--	--	--	--	--	--	--	--	--	0.17	--	12.16	--	304
FUG AREA 2	N/A	FUG AREA 2	Fugitive Area 2 (Frac 2)	--	--	--	--	7.92	34.70	--	--	--	--	--	--	--	--	--	0.34	--	23.17	--	580
S033	N/A	P033	Barge Loading Vent	--	--	--	--	97.22	82.69	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S002	N/A	P002	Fire Pump #1 (700 hp)	4.63	0.23	4.01	0.20	4.63	0.23	0.23	0.01	0.23	0.01	0.23	0.01	0.01	0.0004	--	--	--	--	--	41
S003	N/A	P003	Fire Pump #2 (700 hp)	4.63	0.23	4.01	0.20	4.63	0.23	0.23	0.01	0.23	0.01	0.23	0.01	0.01	0.0004	--	--	--	--	--	41
TK-907	N/A	TK-907	Produced Water Tank TK-907	--	--	--	--	26.96	0.14	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S015	N/A	P015	Slop Water Truck Loading	--	--	--	--	2.32	0.11	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-L-1	N/A	TK-L-1	Gasoline Dispensing Tank	--	--	--	--	15.71	0.13	--	--	--	--	--	--	--	--	--	--	--	--	--	--
L-1	N/A	L-1	Gasoline Dispenser Loading	--	--	--	--	0.18	0.07	--	--	--	--	--	--	--	--	--	--	--	--	--	--
PLANT 3 SOURCES																							
S024	N/A	P024	Regen Gas Heater (9.7 MMBtu/hr)	0.95	4.17	0.80	3.50	0.05	0.23	0.07	0.32	0.07	0.32	0.07	0.32	0.01	0.03	--	--	--	--	--	4,975
S026	N/A	P026	Cryo HMO Heater (26.3 MMBtu/hr)	2.58	11.29	2.17	9.49	0.14	0.62	0.20	0.86	0.20	0.86	0.20	0.86	0.02	0.08	--	--	--	--	--	13,489
FUG AREA 3	N/A	FUG AREA 3	Fugitive Area 3 (Cryo 3)	--	--	--	--	3.10	13.56	--	--	--	--	--	--	--	--	--	0.14	--	9.95	--	249
PLANT 4 SOURCES																							
S036	N/A	P036	Regen Gas Heater (9.7 MMBtu/hr)	0.95	4.17	0.80	3.50	0.05	0.23	0.07	0.32	0.07	0.32	0.07	0.32	0.01	0.03	--	--	--	--	--	4,975
S037	N/A	P037	Cryo HMO Heater (26.3 MMBtu/hr)	2.58	11.29	2.17	9.49	0.14	0.62	0.20	0.86	0.20	0.86	0.20	0.86	0.02	0.08	--	--	--	--	--	13,489
FUG AREA 4	N/A	FUG AREA 4	Fugitive Area 4 (Cryo 4)	--	--	--	--	3.91	17.12	--	--	--	--	--	--	--	--	--	0.22	--	15.74	--	394
			Total (PTE excluding fugitives)[a]:	**1,852.55**	**310.63**	**3,798.66**	**293.86**	**10,783.03**	**188.54**	**71.07**	**109.42**	**71.07**	**109.42**	**71.07**	**109.42**	**15.26**	**33.47**	**519,239**	**1,471,306**	**9.04**	**43.68**	**519,721**	**1,917,812**
			Site Total:	**1,852.55**	**310.63**	**3,798.66**	**293.86**	**10,810.56**	**309.11**	**71.07**	**153.28**	**71.07**	**121.11**	**71.07**	**110.59**	**15.26**	**33.47**	**519,239**	**1,471,307**	**9.04**	**134.54**	**519,721**	**1,920,085**
			Previously Authorized Emissions (Permit R13-2896J):		**310.63**		**293.86**		**362.80**		**153.28**		**121.11**		**110.59**		**33.47**						**1,920,955**
			Change in Allowables:	**0.00**	**0.00**	**-53.69**	**0.00**	**0.00**	**0.00**	**0.00**													**-870.78**
			Nested Boilers Source Previously Authorized Emissions (Permit R13-2896J):	**165.83**	**180.51**	**14.97**	**25.54**	**25.54**	**25.54**	**2.41**													**401,301**
			Total Nested PSD Sources (Boilers):	**165.83**	**180.51**	**14.97**	**25.54**	**25.54**	**25.54**	**2.41**													**401,301**
			PSD Major Source Nested Sources Threshold:	**100**	**100**	**100**	**100**	**100**	**100**	**100**													**100,000**
			Nested Boilers Source Project-related Increases:	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**													**0**
			Nested Power Plant Source Previously Authorized Emissions (Permit R13-3493):	**98.92**	**58.40**	**9.17**	**81.09**	**81.09**	**81.09**	**30.83**													**1,459,618**
			Total Nested PSD Sources (Power Plant):	**98.92**	**58.40**	**9.17**	**81.09**	**81.09**	**81.09**	**30.83**													**1,459,618**
			PSD Major Source Nested Sources Threshold:	**100**	**100**	**100**	**100**	**100**	**100**	**100**													**100,000**
			Nested Power Plant Source Project-related Increases:	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**													**0**

[a] Fugitive emissions are excluded for the purpose of determining major source status under 40 CFR §52.21.

TABLE N-2
SUMMARY OF SITE-WIDE HAZARDOUS AIR POLLUTANT EMISSION RATES
CLASS II ADMINISTRATIVE UPDATE
NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT
BLUE RACER MIDSTREAM, LLC

				Potential to Emit															
				CH_2O		N-Hexane		Benzene		Toluene		Ethylbenzene		Xylene		Methanol		Other HAPS		Total HAPs	
Emission Unit ID	Control Device ID	Emission Point ID	Description	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)
AUTHORIZED SOURCES (UNDER CONSTRUCTION)																			
S052	N/A	P052	Hot Oil Heater (61.6 MMBtu/hr)	4.53E-03	1.98E-02	2.78E-04	1.22E-03	1.27E-04	5.55E-04	2.05E-04	8.99E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.17E-04	5.12E-04	5.25E-03	2.30E-02
S053	N/A	P053	Hot Oil Heater (61.6 MMBtu/hr)	4.53E-03	1.98E-02	2.78E-04	1.22E-03	1.27E-04	5.55E-04	2.05E-04	8.99E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.17E-04	5.12E-04	5.25E-03	2.30E-02
S054	C011	P054	Ethane Amine Regenerator	--	--	--	--	--	--	--	--	--	--	--	--	1.82E+00	4.00E-01	--	--	1.82E+00	4.00E-01
S056	N/A	P056	Stabilizer Heater	7.42E-04	3.25E-03	4.55E-05	1.99E-04	2.08E-05	9.10E-05	3.36E-05	1.47E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.91E-05	8.38E-05	8.61E-04	3.77E-03
S058	N/A	P058	Fire Pump Engine(s)	1.66E-03	8.32E-05	--	--	1.64E-02	8.18E-04	5.92E-03	2.96E-04	--	--	4.07E-03	2.03E-04	--	--	5.17E-03	2.58E-04	3.32E-02	1.66E-03
TK-2906	N/A	TK-2906	Slop Tank TK-2906	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-2907	N/A	TK-2907	Produced Water Tank TK-2907	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-3802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-3802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-4802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-4802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-5802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-5802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-6802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-6802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-7802	C012	TK-7802	Refrigerated Propane Storage Tank TK-7802, with VRU to recapture vapors and recondense back to storage (insignificant intermittent source).	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
PLANT 5 SOURCES																			
S040	N/A	P040	Regen Gas Heater (19.28 MMBtu/hr)	1.42E-03	6.21E-03	8.69E-05	3.81E-04	3.97E-05	1.74E-04	6.43E-05	2.81E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.66E-05	1.60E-04	1.65E-03	7.21E-03
S041	N/A	P041	Cryo HMO Heater (54.67 MMBtu/hr)	4.02E-03	1.76E-02	2.47E-04	1.08E-03	1.13E-04	4.93E-04	1.82E-04	7.98E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.04E-04	4.54E-04	4.66E-03	2.04E-02
FUG AREA 5	N/A	FUG AREA 5	Fugitive Area 5 (Cryo 5)	--	--	9.26E-03	4.06E-02	1.84E-04	8.07E-04	2.57E-04	1.13E-03	0.00E+00	0.00E+00	9.12E-05	3.99E-04	--	--	--	--	9.79E-03	4.29E-02
PLANT 6 SOURCES																			
S044	N/A	P044	Regen Gas Heater (9.7 MMBtu/hr)	7.13E-04	3.12E-03	5.99E-05	2.62E-04	2.00E-05	8.75E-05	3.23E-05	1.42E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E-05	8.06E-05	8.44E-04	3.70E-03
S045	N/A	P045	Cryo HMO Heater (26.3 MMBtu/hr)	1.93E-03	8.47E-03	1.19E-04	5.20E-04	5.41E-05	2.37E-04	8.77E-05	3.84E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.99E-05	2.18E-04	2.24E-03	9.83E-03
FUG AREA 6	N/A	FUG AREA 6	Fugitive Area 6 (Cryo 6)	--	--	9.26E-03	4.06E-02	1.84E-04	8.07E-04	2.57E-04	1.13E-03	0.00E+00	0.00E+00	9.12E-05	3.99E-04	--	--	--	--	9.79E-03	4.29E-02
PLANT 7 SOURCES																			
S048	N/A	P048	Regen Gas Heater (9.7 MMBtu/hr)	7.13E-04	3.12E-03	5.99E-05	2.62E-04	2.00E-05	8.75E-05	3.23E-05	1.42E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E-05	8.06E-05	8.44E-04	3.70E-03
S049	N/A	P049	Cryo HMO Heater (26.3 MMBtu/hr)	1.93E-03	8.47E-03	1.19E-04	5.20E-04	5.41E-05	2.37E-04	8.77E-05	3.84E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.99E-05	2.18E-04	2.24E-03	9.83E-03
FUG AREA 7	N/A	FUG AREA 7	Fugitive Area 7 (Cryo 7)	--	--	9.26E-03	4.06E-02	1.84E-04	8.07E-04	2.57E-04	1.13E-03	0.00E+00	0.00E+00	9.12E-05	3.99E-04	--	--	--	--	9.79E-03	4.29E-02
POWER PLANT																			
PWR PLNT	N/A	Various	Power Plant Total PTE	1.53	6.13	2.54E-03	2.65E-03	4.33E-02	1.10E-01	2.70E-01	1.14	6.35E-02	2.80E-01	1.30E-01	5.60E-01	--	--	1.90E-01	6.90E-01	2.21	8.83
EXISTING SOURCES																			
S001	N/A	P001	Hot Oil Heater (216.7 MMBtu/hr)	5.02E-03	2.20E-02	8.71E-05	3.81E-04	1.41E-04	6.16E-04	2.28E-04	9.97E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.30E-04	5.68E-04	5.61E-03	2.46E-02
S016	N/A	P016	Hot Oil Heater (61.6 MMBtu/hr)	4.53E-03	1.98E-02	2.78E-04	1.22E-03	1.27E-04	5.55E-04	2.05E-04	8.99E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.17E-04	5.12E-04	5.25E-03	2.30E-02
S017	N/A	P017	Hot Oil Heater (61.6 MMBtu/hr)	4.53E-03	1.98E-02	2.78E-04	1.22E-03	1.27E-04	5.55E-04	2.05E-04	8.99E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.17E-04	5.12E-04	5.25E-03	2.30E-02
S018	N/A	P018	Hot Oil Heater (61.6 MMBtu/hr)	4.53E-03	1.98E-02	2.78E-04	1.22E-03	1.27E-04	5.55E-04	2.05E-04	8.99E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.17E-04	5.12E-04	5.25E-03	2.30E-02
S019	N/A	P019	Hot Oil Heater (61.6 MMBtu/hr)	4.53E-03	1.98E-02	2.78E-04	1.22E-03	1.27E-04	5.55E-04	2.05E-04	8.99E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.17E-04	5.12E-04	5.25E-03	2.30E-02
S012	N/A	P012	Regen Gas Heater (9.7 MMBtu/hr)	7.13E-04	3.12E-03	5.99E-05	2.62E-04	2.00E-05	8.75E-05	3.23E-05	1.42E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E-05	8.06E-05	8.44E-04	3.70E-03
S013	N/A	P013	Cryo HMO Heater (26.3 MMBtu/hr)	1.93E-03	8.47E-03	1.19E-04	5.20E-04	5.41E-05	2.37E-04	8.77E-05	3.84E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.99E-05	2.18E-04	2.24E-03	9.83E-03
S006	C001	P001	Glycol Dehydrator Still Vent	--	--	3.91E-02	1.71E-01	3.04E-02	1.33E-01	5.25E-02	2.30E-01	0.00E+00	0.00E+00	2.89E-02	1.27E-01	--	--	--	--	1.51E-01	6.61E-01
S004A	*C004A*	*P004A*	*Ground Flare*	--	--	*4.53E+00*	*1.19E-01*	*1.90E-03*	*8.50E-04*	*2.64E-03*	*1.18E-03*	*0.00E+00*	*0.00E+00*	*9.37E-04*	*4.20E-04*	--	--	--	--	*4.53E+00*	*1.21E-01*
S034	C034	P034	Flare (Pigging)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S035	*N/A*	*P035*	*Pigging Vent*	--	--	*1.20E+00*	*9.54E-03*	*1.79E-02*	*1.55E-04*	*2.50E-02*	*2.16E-04*	*0.00E+00*	*0.00E+00*	*8.88E-03*	*7.67E-05*	--	--	--	--	*1.25E+00*	*9.99E-03*
TK-906	N/A	TK-906	Slop Tank TK-906	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S011	N/A	P005	Ethane Amine Regenerator	--	--	--	--	--	--	--	--	--	--	--	--	1.82E+00	7.99E+00	--	--	1.82E+00	7.99E+00
TK-802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

TABLE N-2
SUMMARY OF SITE-WIDE HAZARDOUS AIR POLLUTANT EMISSION RATES
CLASS II ADMINISTRATIVE UPDATE
NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT
BLUE RACER MIDSTREAM, LLC

				Potential to Emit															
				CH_2O		N-Hexane		Benzene		Toluene		Ethylbenzene		Xylene		Methanol		Other HAPS		Total HAPs	
Emission Unit ID	Control Device ID	Emission Point ID	Description	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)
TK-2802	C001 and VRU	P001	Natural Gasoline Storage Tank TK-2802, with Natural Gas Blanket and VRU to Hot Oil Heater (insignificant intermittent source)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S008	Vapor Return to Tank	P008	Propane, i-Butane, Butanes, and Natural Gasoline Loading (Truck, Railcar, and Propane Barge)	--	--	6.68E-02	1.05E-02	1.35E-02	2.13E-03	1.38E-02	2.16E-03	7.79E-04	1.22E-04	4.00E-03	6.29E-04	--	--	--	--	9.88E-02	1.55E-02
S055	N/A	P055	Pressurized NGL/Condensate Unloading	--	--	3.40E-01	7.45E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	--	--	--	--	3.40E-01	7.45E-01
ROADS	N/A	ROADS	Unpaved Roads	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
FUG AREA 1	N/A	FUG AREA 1	Fugitive Area 1 (Cryo 1, Cryo 2, and Frac 1)	--	--	1.13E-02	4.95E-02	2.25E-04	9.86E-04	3.14E-04	1.38E-03	0.00E+00	0.00E+00	1.11E-04	4.88E-04	--	--	0.00E+00	0.00E+00	1.20E-02	5.24E-02
FUG AREA 2	N/A	FUG AREA 2	Fugitives Area 2 (Frac 2)	--	--	2.21E-02	9.69E-02	4.40E-04	1.93E-03	6.14E-04	2.69E-03	0.00E+00	0.00E+00	2.18E-04	9.54E-04	--	--	0.00E+00	0.00E+00	2.34E-02	1.03E-01
S033	N/A	P033	Barge Loading Vent	--	--	--	--	4.38E-01	3.72E-01	7.29E-01	6.20E-01	--	--	2.82E-01	2.40E-01	--	--	--	--	1.45E+00	1.23E+00
S002	N/A	P002	Fire Pump #1 (700 hp)	3.88E-04	1.94E-05	--	--	3.82E-03	1.91E-04	1.38E-03	6.91E-05	--	--	9.49E-04	4.75E-05	--	--	1.21E-03	6.03E-05	7.74E-03	3.87E-04
S003	N/A	P003	Fire Pump #2 (700 hp)	3.88E-04	1.94E-05	--	--	3.82E-03	1.91E-04	1.38E-03	6.91E-05	--	--	9.49E-04	4.75E-05	--	--	1.21E-03	6.03E-05	7.74E-03	3.87E-04
TK-907	N/A	TK-907	Produced Water Tank TK-907	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
S015	N/A	P015	Slop Water Truck Loading	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
TK-L-1	N/A	TK-L-1	Gasoline Dispensing Tank	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
L-1	N/A	L-1	Gasoline Dispenser Loading	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
PLANT 3 SOURCES																					
S024	N/A	P024	Regen Gas Heater (9.7 MMBtu/hr)	7.13E-04	3.12E-03	5.99E-05	2.62E-04	2.00E-05	8.75E-05	3.23E-05	1.42E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E-05	8.06E-05	8.44E-04	3.70E-03
S026	N/A	P026	Cryo HMO Heater (26.3 MMBtu/hr)	1.93E-03	8.47E-03	1.19E-04	5.20E-04	5.41E-05	2.37E-04	8.77E-05	3.84E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.99E-05	2.18E-04	2.24E-03	9.83E-03
FUG AREA 3	N/A	FUG AREA 3	Fugitive Area 3 (Cryo 3)	--	--	9.26E-03	4.06E-02	1.84E-04	8.07E-04	2.57E-04	1.13E-03	0.00E+00	0.00E+00	9.12E-05	3.99E-04	--	--	--	--	9.79E-03	4.29E-02
PLANT 4 SOURCES																					
S036	N/A	P036	Regen Gas Heater (9.7 MMBtu/hr)	7.13E-04	3.12E-03	5.99E-05	2.62E-04	2.00E-05	8.75E-05	3.23E-05	1.42E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E-05	8.06E-05	8.44E-04	3.70E-03
S037	N/A	P037	Cryo HMO Heater (26.3 MMBtu/hr)	1.93E-03	8.47E-03	1.19E-04	5.20E-04	5.41E-05	2.37E-04	8.77E-05	3.84E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.99E-05	2.18E-04	2.24E-03	9.83E-03
FUG AREA 4	N/A	FUG AREA 4	Fugitive Area 4 (Cryo 4)	--	--	1.46E-02	6.41E-02	2.91E-04	1.28E-03	4.07E-04	1.78E-03	0.00E+00	0.00E+00	1.44E-04	6.32E-04	--	--	--	--	1.55E-02	6.78E-02
			Change in PTE:	**0.00**	**0.00**	**-0.03**	**-0.16**	**0.00**	**-0.01**	**0.00**	**-0.01**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**-0.03**	**-0.18**
			Total:	**1.58**	**6.36**	**6.26**	**1.44**	**0.57**	**0.63**	**1.11**	**2.01**	**0.064**	**0.2801**	**0.46**	**0.93**	**3.65**	**8.39**	**0.20**	**0.70**	**13.88**	**20.66**
			Major Source Thresholds:		**10**		**10**		**10**		**10**		**10**		**10**		**10**				**25**

TABLE N-3
SUMMARY OF DE-MINIMIS SOURCES
AIR PERMIT APPLICATION
NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT
BLUE RACER MIDSTREAM, LLC

Emission Unit ID	Control Device ID	Emission Point ID	Description	De-minimis Justification
Authorized Sources (Under Construction)				
US-2801	N/A	US-2801	Spherical Storage Tank US-2801	Pressurized. No emissions other than fugitive components.
US-2804	N/A	US-2804	Spherical Storage Tank US-2804	Pressurized. No emissions other than fugitive components.
US-2805	N/A	US-2805	Spherical Storage Tank US-2805	Pressurized. No emissions other than fugitive components.
V-2905	N/A	V-2905	Pressurized Bullet Tank V-2905	Pressurized. No emissions other than fugitive components.
V-2915	N/A	V-2915	Pressurized Bullet Tank V-2915	Pressurized. No emissions other than fugitive components.
V-2925	N/A	V-2925	Pressurized Bullet Tank V-2925	Pressurized. No emissions other than fugitive components.
V-2935	N/A	V-2935	Pressurized Bullet Tank V-2935	Pressurized. No emissions other than fugitive components.
UK-3520	N/A	UK-3520	Amine Sump	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-3524	N/A	TK-3524	Amine Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
UT-608	N/A	UT-608	Glycol Sump (Water)	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
MH-001	N/A	MH-001	Portable Maintenance Heater	Maintenance and upkeep activity not related to principal business activity.
Existing Sources				
N/A	N/A	N/A	Refrigeration Compressors (Electric)	No emissions other than fugitive components.
N/A	N/A	N/A	Residue Gas Compressors (Electric)	No emissions other than fugitive components.
N/A	N/A	N/A	Ethane Compressors (Electric)	No emissions other than fugitive components.
US-800	N/A	US-800	Spherical Storage Tank US-800	Pressurized. No emissions other than fugitive components.
US-801	N/A	US-801	Spherical Storage Tank US-801	Pressurized. No emissions other than fugitive components.
US-804	N/A	US-804	Spherical Storage Tank US-804	Pressurized. No emissions other than fugitive components.
US-805	N/A	US-805	Spherical Storage Tank US-805	Pressurized. No emissions other than fugitive components.
US-2800	N/A	US-2800	Spherical Storage Tank US-2800	Pressurized. No emissions other than fugitive components.
V-1905	N/A	V-1905	Pressurized Bullet Tank V-1905	Pressurized. No emissions other than fugitive components.
V-1915	N/A	V-1915	Pressurized Bullet Tank V-1915	Pressurized. No emissions other than fugitive components.
V-1925	N/A	V-1925	Pressurized Bullet Tank V-1925	Pressurized. No emissions other than fugitive components.
V-1935	N/A	V-1935	Pressurized Bullet Tank V-1935	Pressurized. No emissions other than fugitive components.
TK-950	N/A	TK-950	Firewater Tank	Tank does not store organic liquids.
TK-605	N/A	TK-605	TEG Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2605	N/A	TK-2605	TEG Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-119A	N/A	TK-119A	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-119B	N/A	TK-119B	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-840	N/A	TK-840	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-810	N/A	TK-810	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-850	N/A	TK-850	Used Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2436	N/A	TK-2436	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
UT-909	N/A	UT-909	Open Drain Sump (Oil/Water)	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2119A	N/A	TK-2119A	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2119B	N/A	TK-2119B	Lube Oil Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
UK-2520	N/A	UK-2520	Amine Sump	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2524	N/A	TK-2524	Amine Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-2522	N/A	TK-2522	Treated Water Storage Tank	Tank does not store organic liquids.
UT-607	N/A	UT-607	Glycol Sump (Water)	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
UT-2909	N/A	UT-2909	Open Drain Sump (Oil/Water)	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-952B	N/A	TK-952B	Diesel Fuel Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-952C	N/A	TK-952C	Diesel Fuel Storage Tank	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.
TK-452	N/A	TK-452	Spent Caustic Tank	No emissions, out of service.
TK-453	N/A	TK-453	Caustic Tank	No emissions, out of service.
N/A	N/A	N/A	Hotsy Pressure Washer	Onsite maintenance and upkeep activity.
N/A	N/A	N/A	Hot Air Blower	Onsite maintenance and upkeep activity.
N/A	N/A	N/A	On-site Sewage Treatment Plant	Onsite maintenance and upkeep activity.
N/A	N/A	N/A	Diesel Fuel Cell	Vapor pressure less than 1.5 psia and tank capacity less than 10,567 gal.

GROUND FLARE POTENTIAL TO EMIT

AIR PERMIT MODIFICATION APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID **S004A**

Pilot Emissions- Continual

Pilot fuel consumption	1,530.00	scf/hr
Pilot heat input rating	1.629	MMBtu/hr
Fuel gas HHV	1,065	Btu/ft^3
Annual operating hours	8,760	hr/yr

Waste Gas Streams

Source	Purge Gas [7]	Pigging	Blowdowns	Closed Vent System	Irregular Process Vents	Ethane Treater S011 Flash Tank	Ethane Treater S054 Flash Tank	Total
Total hourly heat input to flare (MMBtu/hr)	0.12	82.77	11,068.83	0.62	0.78	0.93	0.93	11,154.97
Total annual heat input to flare (MMBtu/yr)	1,091.24	1,691.25	166,262.65	5,400.12	6,790.07	8,111.69	8,111.69	197,458.70
Total hourly gas volume to flare (scf/hr)	117.00	31,000.00	4,000,000.00	540.74	570.78	525.78	525.78	4,033,280.07
Total annual gas volume to flare (MMscf/yr)	1.02	0.88	98.46	4.74	5.00	4.61	4.61	119.31
Hourly VOC to flare (lb/hr)	--	3,281.92	504,341.26	6.34	7.44	0.48	0.48	507,637.92
Annual VOC to flare (T/yr)	--	20.08	1,884.54	27.78	32.57	2.11	2.11	1,969.19
Hourly CO2 to flare (lb/hr)			6.86		0.08			6.94
Annual CO2 to flare (T/yr)		0.39	6.00		0.36			6.75
Hourly CH4 to flare (lb/hr)			1,509.55	3.54	16.75			1,529.84
Annual CH4 to flare (T/yr)		6.49	1,242.84	15.50	73.36			1,338.18
Hourly HAP to flare (lb/hr)	--	186.63	39.54	0.08	0.36	0.002	0.002	226.63
Annual HAP to flare (T/yr)	--	1.12	2.99	0.36	1.60	0.01	0.01	6.09

Flare control efficiency 98.0%

Pollutant	CAS	REF	Emission Factor	Units	Potential Emissions lb/hr	Potential Emissions tons/yr
Pilot						
Criteria Pollutants						
NO_X	N/A	1	0.138	lb/MMBtu	0.22	0.98
CO	630-08-0	1	0.2755	lb/MMBtu	0.45	1.97
VOC	N/A	3	5.5	lb/MMscf	0.01	0.04
PM_{10}	N/A	3	7.6	lb/MMscf	0.01	0.05
$PM_{2.5}$	N/A	3	7.6	lb/MMscf	0.01	0.05
SO_2	7446-09-5	2	4.0	ppm	0.001	0.005
Waste Gas						
Criteria Pollutants						
NO_X	N/A	1	0.138	lb/MMBtu	1,539.39	13.62
CO	630-08-0	1	0.2755	lb/MMBtu	3,073.19	27.20
VOC - combustion	N/A	3	5.5	lb/MMscf	22.18	0.33
VOC - controlled process stream	N/A	---	507,638	lb/hr	10,152.76	39.38
PM_{10}	N/A	3	7.6	lb/MMscf	30.65	0.45
$PM_{2.5}$	N/A	3	7.6	lb/MMscf	30.65	0.45
HAP - controlled process stream	N/A	---	227	lb/hr	4.53	0.12
Greenhouse Gases (Pilot and Purge)						
Carbon dioxide	124-38-9	4	53.06	kg/MMBtu	205.13	898.45
Methane	74-82-8	5	1.0E-03	kg/MMBtu	0.004	0.02
Nitrous oxide	10024-97-2	5	1.0E-04	kg/MMBtu	0.0004	0.002
CO_2e	N/A	6	---	---	205.34	899.38
TOTAL						
Criteria Pollutants						
NO_X	N/A	---	---	---	1,539.61	14.61
CO	630-08-0	---	---	---	3,073.64	29.17
VOC	N/A	---	---	---	10,174.95	39.75
PM_{10}	N/A	---	---	---	30.66	0.50
$PM_{2.5}$	N/A	---	---	---	30.66	0.50
SO_2	7446-09-5	---	---	---	0.001	0.005

Notes:

1. CO and NO_x are based upon TNRCC Guidance Document for Flares (dated 10/00) for non-assisted high-BTU flares.
2. SO_2 is estimated using a mass balance approach and the actual sulfur content of the gas.
3. AP-42 Table 1.4-2
4. 40 CFR 98 Table C-1
5. 40 CFR 98 Table C-2
6. 40 CFR 98 Table A-1
7. During normal operations, purge gas is recovered by VRU and routed back to inlet. Purge gas combustion only occurs when waste gas is being combusted at the flare (purge gas is not continuous). Hourly rate is based on average use through the year. Purge gas volume is determined by the amount of waste gas routed to flare.
8. Hourly emission rates based on flare flows due to quantifiable events. Hourly emissions may be exceeded due to unpredictable events requiring an emergency shutdown (ESD).

Waste gas GHG combustion emissions calculated in accordance with 40 CFR 98 Subpart W.

BLOWDOWN POTENTIAL TO EMIT

AIR PERMIT MODIFICATION APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Case	MW (lb/lb-mol)	Heating Value[1] (Btu/scf)	**1** Inlet Comp. Blowdown	**2** Residue Comp. Blowdown	**3** Stab. Comp. Blowdown	**4** Ethane Comp. Blowdown	**5** Butane System Blowdown	**6** Site-Wide Blowdown
Compound			mol%	mol%	mol%	mol%	mol%	mol%
water	18.00	0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
carbon dioxide	44.00	0	0.1490	0.1520	0.0010	0.0310	0.0000	0.0000
nitrogen	28.00	0	0.3320	0.3430	0.0040	0.0010	0.0000	0.0000
methane	16.04	1,012	81.7370	91.7190	0.0000	0.4630	0.0000	0.0000
ethane	30.07	1,783	11.9690	7.6050	30.7740	99.4440	0.0000	0.0000
propane	44.10	2,557	3.5880	0.1720	39.7240	0.0580	1.1839	100.0000
Isobutane	58.12	3,354	0.6170	0.0020	7.8150	0.0000	48.2631	0.0000
n-butane	58.12	3,369	0.8980	0.0010	11.5310	0.0000	50.2350	0.0000
Isopentane	72.15	4,001	0.2660	0.0000	3.4790	0.0000	0.3135	0.0000
n-pentane	72.15	4,009	0.2040	0.0000	2.3580	0.0000	0.0030	0.0000
cyclopentane				0.0000				0.0000
n-hexane	86.17	4,756	0.0498	0.0030	2.5890	0.0000	0.0020	0.0000
cyclohexane				0.0000				0.0000
other hexanes	86.17	4,756	0.1061	0.0000	0.0000	0.0000	0.0000	0.0000
heptane	100.21	5,502	0.0555	0.0010	1.2940	0.0000	0.0000	0.0000
benzene	78.11	3,741	0.0011	0.0000	0.0000	0.0000	0.0000	0.0000
toluene	92.14	4,408	0.0013	0.0000	0.0000	0.0000	0.0000	0.0000
ethylbenzene	106.17	5,222	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
xylene	106.16	5,155	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
octane (C8+)	114.23	6,239	0.0248	0.0000	0.4310	0.0000	0.0000	0.0000
hydrogen sulfide	34.08	0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Events/yr			756	972	108	180	6	1
Volume per Event (scf)			38,940	38,940	3,340	38,940	3,300,000	4,000,000
VOC Loading (lb/hr)			310	8	326	3	504,341	464,822
VOC Loading (tpy)			117.24	4.05	17.58	0.24	1513.02	232.41
CO_2 Loading (lb/hr)			6.73	6.86	0.004	1.40	0.00	0.00
CO_2 Loading (tpy)			2.54	3.34	0.00021	0.13	0.00	0.00
CH_4 Loading (lb/hr)			1,345.26	1,509.55	0.00	7.62	0.00	0.00
CH_4 Loading (tpy)			508.51	733.64	0.00	0.69	0.00	0.00
Ethane Loading (lb/hr)			369.30	234.65	81.44	3,068.29	0.00	0.00
Ethane Loading (tpy)			139.59	114.04	4.40	276.15	0.00	0.00
n-Hexane Loading (lb/hr)			4.40	0.27	19.63	0.00	14.99	0.00
n-hexane Loading (tpy)			1.66	0.13	1.06	0.00	0.04	0.00
Benzene Loading (lb/hr)			0.09	0.00	0.00	0.00	0.00	0.00
Benzene Loading (tpy)			0.033	0.00	0.00	0.00	0.00	0.00
Toluene Loading (lb/hr)			0.12	0.00	0.00	0.00	0.00	0.00
Toluene Loading (tpy)			0.046	0.00	0.00	0.00	0.00	0.00
Ethylbenzene Loading (lb/hr)			0.00	0.00	0.00	0.00	0.00	0.00
Ethylbenzene Loading (tpy)			0.00	0.00	0.00	0.00	0.00	0.00
Xylene Loading (lb/hr)			0.04	0.00	0.00	0.00	0.00	0.00
Xylene Loading (tpy)			0.016	0.00	0.00	0.00	0.00	0.00
HAP Loading (lb/hr)			4.66	0.27	19.63	0.00	14.99	0.00
HAP Loading (tpy)			1.76	0.13	1.06	0.00	0.04	0.00
Capacity (MMscf/yr)			29.4386	37.8497	0.3607	7.0092	19.8000	4.0000
Heat Content (Btu/scf)			1,214	1,068	2,670	1,779	3,354	2,557
Heat Input (MMBtu/hr)			47	42	9	69	11,069	10,228
Heat Input (MMBtu/yr)			35,745	40,442	963	12,471	66,413	10,228

Train	Unit ID	Service Type	Annual Events
1	C104A	Inlet	36
	C104B	Inlet	36
	C104C	Inlet	36
	C426A	Ethane	36
	C426B	Ethane	36
	C208A	Residue	36
	C208B	Residue	36
	C208C	Residue	36
	C436	Stabilizer	36
	C445	Butane	6
2	C-100	Inlet	36
	C-110	Inlet	36
	C-120	Inlet	36
	C426C	Ethane	36
	C426D	Ethane	36
	C426E	Ethane	36
	C-150	Residue	36
	C-160	Residue	36
	C-170	Residue	36
	C-180	Residue	36
	C2436	Stabilizer	36
3	C-3100	Inlet	36
	C-3110	Inlet	36
	C-3120	Inlet	36
	C-3150	Residue	36
	C-3160	Residue	36
	C-3170	Residue	36
	C-3180	Residue	36
	C3436	Stabilizer	36
4	C-4100	Inlet	36
	C-4110	Inlet	36
	C-4120	Inlet	36
	C-4150	Residue	36
	C-4160	Residue	36
	C-4170	Residue	36
	C-4180	Residue	36
5	C-5100	Inlet	36
	C-5110	Inlet	36
	C-5120	Inlet	36
	C-5150	Residue	36
	C-5160	Residue	36
	C-5170	Residue	36
	C-5180	Residue	36
6	C-6100	Inlet	36
	C-6110	Inlet	36
	C-6120	Inlet	36
	C-6150	Residue	36
	C-6160	Residue	36
	C-6170	Residue	36
	C-6180	Residue	36
7	C-7100	Inlet	36
	C-7110	Inlet	36
	C-7120	Inlet	36
	C-7150	Residue	36
	C-7160	Residue	36
	C-7170	Residue	36
	C-7180	Residue	36

1. Gross heating values obtained from http://www.scribd.com/doc/118497630/Calculate-Gas-Heating-Value-From-Gas-Composition. For C6+ compounds, the heating value of n-hexane was used.

IRREGULAR PROCESS VENT POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Case	MW (lb/lb-mol)	Heating Value[1] (Btu/scf)	**1** Inlet Stream	**2** Residue Stream	**3** Stabilizer Overheads	**4** Ethane Stream
Compound			mol%	mol%	mol%	mol%
water	18.00	0	0.0000	0.0000	0.0000	0.0000
carbon dioxide	44.00	0	0.1490	0.1520	0.0010	0.0310
nitrogen	28.00	0	0.3320	0.3430	0.0040	0.0010
methane	16.04	1,012	81.7370	91.7190	0.0000	0.4630
ethane	30.07	1,783	11.9690	7.6050	30.7740	99.4440
propane	44.10	2,557	3.5880	0.1720	39.7240	0.0580
Isobutane	58.12	3,354	0.6170	0.0020	7.8150	0.0000
n-butane	58.12	3,369	0.8980	0.0010	11.5310	0.0000
Isopentane	72.15	4,001	0.2660	0.0000	3.4790	0.0000
n-pentane	72.15	4,009	0.2040	0.0000	2.3580	0.0000
cyclopentane			0.0000	0.0000	0.0000	0.0000
n-hexane	86.17	4,756	0.0498	0.0030	2.5890	0.0000
cyclohexane			0.0000	0.0000	0.0000	0.0000
other hexanes	86.17	4,756	0.1061	0.0000	0.0000	0.0000
heptane	100.21	5,502	0.0555	0.0010	1.2940	0.0000
benzene	78.11	3,741	0.0011	0.0000	0.0000	0.0000
toluene	92.14	4,408	0.0013	0.0000	0.0000	0.0000
ethylbenzene	106.17	5,222	0.0000	0.0000	0.0000	0.0000
xylene	106.16	5,155	0.0004	0.0000	0.0000	0.0000
octane (C8+)	114.23	6,239	0.0248	0.0000	0.4310	0.0000
hydrogen sulfide	34.08	0	0.0000	0.0000	0.0000	0.0000
Hourly Vent Volume (scf/hr)[2]			228	228	57	57
Annual Vent Volume (MMscf/yr)			2	2	0.5	0.5
VOC Loading (lb/hr)			1.82	0.05	5.56	0.004
VOC Loading (tpy)			7.96	0.21	24.37	0.02
CO_2 Loading (lb/hr)			0.04	0.04	0.0001	0.002
CO_2 Loading (tpy)			0.17	0.18	0.0003	0.01
CH_4 Loading (lb/hr)			7.89	8.85	0.00	0.01
CH_4 Loading (tpy)			34.55	38.77	0.00	0.05
Ethane Loading (lb/hr)			2.17	1.38	1.39	4.50
Ethane Loading (tpy)			9.48	6.03	6.10	19.70
n-Hexane Loading (lb/hr)			0.03	0.00	0.34	0.00
n-hexane Loading (tpy)			0.11	0.01	1.47	0.00
Benzene Loading (lb/hr)			0.001	0.00	0.00	0.00
Benzene Loading (tpy)			0.002	0.00	0.00	0.00
Toluene Loading (lb/hr)			0.001	0.00	0.00	0.00
Toluene Loading (tpy)			0.003	0.00	0.00	0.00
Ethylbenzene Loading (lb/hr)			0.00	0.00	0.00	0.00
Ethylbenzene Loading (tpy)			0.00	0.00	0.00	0.00
Xylene Loading (lb/hr)			0.0003	0.00	0.00	0.00
Xylene Loading (tpy)			0.001	0.00	0.00	0.00
HAP Loading (lb/hr)			0.03	0.002	0.34	0.00
HAP Loading (tpy)			0.12	0.01	1.47	0.00
Heat Content (Btu/scf)			1,214	1,068	2,670	1,779
Heat Input (MMBtu/hr)			0.28	0.24	0.15	0.10
Heat Input (MMBtu/yr)			2,428	2,137	1,335	890

1. Gross heating values obtained from http://www.scribd.com/doc/118497630/Calculate-Gas-Heating-Value-From-Gas-Composition.

PIGGING OPERATIONS POTENTIAL TO EMIT

AIR PERMIT MODIFICATION APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Location	Truck Dock Side						North Side				
Description (per notes)	30" Pig Launcher TL-613 Residue Launcher 24" Barrel	New 30" Pig Receiver TL-613 Residue Receiver 36" Barrel	24" Pig Receiver Inlet Receiver 30" Barrel	New 24" Pig Receiver, 2018 Inlet Receiver 30" Barrel	New Receiver, 2018 Inlet Receiver 30" Barrel	8" Pig Launcher [d] G150 Launcher 12" Barrel	24" Pig Receiver TL-404 Receiver 30" Barrel	20" Pig Launcher Residue Launcher 30" Barrel	10" Pig Launcher G151 Launcher 16" Barrel	10" Pig Launcher B2N Launcher 16" Barrel	8" Pig Receiver B2N Receiver 12" Barrel
Description	Residue	Residue	Inlet	Inlet	Inlet	Propane/Butane [d]	Inlet	Residue	Ethane	Inlet	Condensate/NGL
Number of Events per Year	12	12	365	365	365	10	10	12	12	24	12
Number of Events per Hour	1	1	5	5	5	1	1	1	1	1	1
Volume per Event, scf	18,000	25,600	61	61	61	72,000	7,000	20,000	18,000	2,000	31,000
Gas Stream Specific Gravity	0.5970	0.5970	0.6880	0.6880	0.6880	2.0700	0.6880	0.5970	1.0450	0.6880	1.6300
Air MW, lb/mole	28.96	28.96	28.96	28.96	28.96	28.96	28.96	28.96	28.96	28.96	28.96
Gas Stream Density, lb/scf [a]	0.046	0.046	0.053	0.053	0.053	0.158	0.053	0.046	0.080	0.053	0.125
Control Type (Flare/Vent)	Vent	Vent	Vent	Vent	Vent	Flare	Vent	Flare	Flare	Flare	Flare
Flare Control Efficiency, %	0%	0%	0%	0%	0%	98%	0%	98%	98%	98%	98%
Flare Unit ID	--	--	--	--	--	S034	--	S004A	S004A	S004A	S004A
Waste Gas Heat Content (Btu/scf)	1,065	1,065	1,212	1,212	1,212	2,371	1,212	1,065	1,779	1,212	2,670
Heat Input to Flare (MMBtu/hr)	N/A	N/A	N/A	N/A	N/A	170.71	N/A	21.29	32.03	2.42	82.77
Heat Input to Flare (MMBtu/yr)	N/A	N/A	N/A	N/A	N/A	1,707.12	N/A	255.53	384.32	58.17	993.23
Annual flow to flare (MMscf/yr)	N/A	N/A	N/A	N/A	N/A	0.72	N/A	0.24	0.22	0.05	0.37
Max VOC Percentage in Gas Stream, wt%	1.00%	1.00%	20.00%	20.00%	20.00%	100.00%	20.00%	1.00%	1.00%	20.00%	85.00%
Max H_2S Percentage in Gas Stream, wt%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Max Methane Percentage in Gas Stream, wt%	95.00%	95.00%	70.00%	70.00%	70.00%	0.00%	70.00%	95.00%	2.00%	70.00%	1.00%
Max CO_2 Percentage in Gas Stream, wt%	1.00%	1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Benzene Percentage in Gas Stream, wt%	0.0000%	0.0000%	0.0043%	0.0043%	0.0043%	0.0000%	0.0043%	0.0000%	0.0000%	0.0043%	0.0000%
Toluene Percentage in Gas Stream, wt%	0.0000%	0.0000%	0.0060%	0.0060%	0.0060%	0.0000%	0.0060%	0.0000%	0.0000%	0.0060%	0.0000%
Ethylbenzene Percentage in Gas Stream, wt%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Xylene Percentage in Gas Stream, wt%	0.0000%	0.0000%	0.0021%	0.0021%	0.0021%	0.0000%	0.0021%	0.0000%	0.0000%	0.0021%	0.0000%
n-Hexane Percentage in Gas Stream, wt%	0.0150%	0.0150%	0.2157%	0.2157%	0.2157%	0.0059%	0.2157%	0.0150%	0.0000%	0.2157%	4.8240%
Hourly VOC Emission Rates (lb/hr): [b]	8.21	11.68	3.20	3.20	3.20	227.77	73.60	0.18	0.29	0.42	65.64
Annual VOC Emission Rates (T/yr): [c]	0.05	0.07	0.12	0.12	0.12	1.14	0.37	0.001	0.002	0.01	0.39
Annual Methane Emission Rates (T/yr): [c]	4.68	6.66	0.41	0.41	0.41	0.00	1.29	0.10	0.003	0.02	0.005
Annual CO_2 Emission Rates (T/yr): [c]	0.05	0.07	0.01	0.01	0.01	0.00	0.02	0.001	0.002	0.0003	0.005
Hourly Benzene Emission Rates (lb/hr):[b]	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.0001	0.00
Annual Benzene Emission Rates (T/yr): [c]	0.00	0.00	0.000	0.000	0.000	0.00	0.0001	0.00	0.00	0.000001	0.00
Hourly Toluene Emission Rates (lb/hr):[b]	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.0001	0.00
Annual Toluene Emission Rates (T/yr): [c]	0.00	0.00	0.000	0.000	0.000	0.00	0.0001	0.00	0.00	0.000002	0.00
Hourly Ethylbenzene Emission Rates (lb/hr):[b]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Ethylbenzene Emission Rates (T/yr): [c]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hourly Xylene Emission Rates (lb/hr):[b]	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00004	0.00
Annual Xylene Emission Rates (T/yr): [c]	0.00	0.00	0.000	0.000	0.000	0.00	0.00004	0.00	0.00	0.000001	0.00
Hourly n-Hexane Emission Rates (lb/hr):[b]	0.12	0.18	0.03	0.03	0.03	0.01	0.79	0.003	0.00	0.005	3.73
Annual n-Hexane Emission Rates (T/yr): [c]	0.001	0.001	0.00	0.00	0.00	0.0001	0.004	0.00002	0.00	0.0001	0.02

[a] Gas stream density is calculated as follows:

(28.96 lb/mole) / (379 scf/mole) * (0.5970) = 0.046 lb/scf

[b] Hourly VOC emission rates are calculated as follows:

(1 event/hr) * (18,000 scf/event) * (0.046 lb/scf) * (1.00% VOC) = 8.21 lb/hr

[c] Annual VOC emission rates are calculated as follows:

(12 events/yr) * (18,000 scf/event) * (0.046 lb/scf) * (1.00% VOC) / (2,000 lb/T) = 0.05 T/yr

[d] Pig launcher in propane service has its own auto-ignition flare to control emissions during pigging operations. Emission calculations from this flare follow.

PIGGING FLARE POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID	Emission Point ID	Description	WG (Propane) Flow Rate[a] (scf/hr)	WG Higher Heating Value (Btu/scf)	Flare Feed Rate Hourly (MMBtu/hr)	Flare Feed Rate Annual (MMBtu/yr)	Annual Hours Hours (hr/yr)	Pollutant	Emission Factors[b]	Units	Potential to Emit Hourly[b] (lb/hr)	Potential to Emit Annual[c] (T/yr)
S034	P034	Flare (Pigging)[e]	72,000	2,371.00	170.71	1,707.12	10	CO	0.0820	lb/MMBtu	13.99	0.07
								NO_X	0.1421	lb/MMBtu	24.25	0.12
								PM[d]	0.0077	lb/MMBtu	1.31	0.01
								SO_2	0.0109	lb/MMBtu	1.87	0.01
								VOC	Material Balance		227.77	1.14

[a] The WG flow rate, heating value, and feed rates taken from calculation of pigging operations potential to emit worksheet.

[b] Emission factors are from AP-42 Table 1.5-1 (dated 7/08) for propane combustion. Emission factors were normalized based on liquid propane heating value of 91,500,000 Btu/10^3 gallons. An example calculation for hourly CO emissions for Emission Unit ID S034 follows:

CO (lb/hr) = (Flare Feed Rate, MMBtu/hr) * (Emission Factor, lb/MMBtu)

CO (lb/hr) = (170.71 MMBtu/hr) * (0.0820 lb/MMBtu)

= 13.99 lb/hr CO

[c] An example calculation for annual CO emissions for Emission Unit ID S034 follows:

CO (T/yr) = (Flare Feed Rate, MMBtu/yr) * (Emission Factor, lb/MMBtu) / (2,000 lb/T)

CO (T/yr) = (1,707.12 MMBtu/yr) * (0.0820 lb/MMBtu) / (2,000 lb/T)

= 0.07 T/yr CO

[d] The flare is smokeless per 40 CFR §60.18 requirements; therefore, PM emissions are negligible. However, PM emissions have been included to be conservative.

[e] The flare has an auto-ignition system. Therefore, the flare does not require a continuous pilot to operate.

HOT OIL AND PLANT HEATERS POTENTIAL TO EMIT

AIR PERMIT CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID	Description	Maximum Hourly Heat Input (MMBtu/hr)	Maximum Annual Heat Input (MMBtu/yr)	Fuel Lower Heating Value (Btu/scf)	Maximum Hourly Fuel Use (scf/hr)	Maximum Annual Fuel Use (MMscf/yr)	Annual Operating Hours (hr/yr)	VOC			NO_X			CO			PM[u]			SO_2[e]		
								Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor (ppm S)	PTE Hourly (lb/hr)	PTE Annual[c] (T/yr)
New Equipment																						
S052	Hot Oil Heater	61.58	539,441	961	64,101	562	8,760	0.0054	0.33	1.45	0.024	1.48	6.47	0.059	3.63	15.91	0.00745	0.46	2.01	4.0	0.04	0.19
S053	Hot Oil Heater	61.58	539,441	961	64,101	562	8,760	0.0054	0.33	1.45	0.024	1.48	6.47	0.059	3.63	15.91	0.00745	0.46	2.01	4.0	0.04	0.19
S056	Stabilizer Heater	10.09	88,388	961	10,503	92	8,760	0.0054	0.05	0.24	0.098	0.99	4.33	0.082	0.83	3.64	0.00745	0.08	0.33	4.0	0.01	0.03
Plant 1 and 2 Equipment																						
S001	Hot Oil Heater	216.70	1,898,292	961	225,571	1,976	8,760	0.0017	0.37	1.61	0.045	9.75	42.71	0.015	3.25	14.24	0.00745	1.61	7.07	4.0	0.15	0.67
S012	Regen Gas Heater	9.7	84,972	961	10,097	88	8,760	0.0054	0.05	0.23	0.098	0.95	4.17	0.082	0.80	3.50	0.00745	0.07	0.32	4.0	0.01	0.03
S013	Cryo HMO Heater	26.3	230,388	961	27,377	240	8,760	0.0054	0.14	0.62	0.098	2.58	11.29	0.082	2.17	9.49	0.00745	0.20	0.86	4.0	0.02	0.08
S016	Hot Oil Heater	61.58	539,441	961	64,101	562	8,760	0.0054	0.33	1.45	0.024	1.48	6.47	0.059	3.63	15.91	0.00745	0.46	2.01	4.0	0.04	0.19
S017	Hot Oil Heater	61.58	539,441	961	64,101	562	8,760	0.0054	0.33	1.45	0.024	1.48	6.47	0.059	3.63	15.91	0.00745	0.46	2.01	4.0	0.04	0.19
S018	Hot Oil Heater	61.58	539,441	961	64,101	562	8,760	0.0054	0.33	1.45	0.024	1.48	6.47	0.059	3.63	15.91	0.00745	0.46	2.01	4.0	0.04	0.19
S019	Hot Oil Heater	61.58	539,441	961	64,101	562	8,760	0.0054	0.33	1.45	0.024	1.48	6.47	0.059	3.63	15.91	0.00745	0.46	2.01	4.0	0.04	0.19
Plant 3 Heaters																						
S024	Regen Gas Heater	9.7	84,972	961	10,097	88	8,760	0.0054	0.05	0.23	0.098	0.95	4.17	0.082	0.80	3.50	0.00745	0.07	0.32	4.0	0.01	0.03
S026	Cryo HMO Heater	26.3	230,388	961	27,377	240	8,760	0.0054	0.14	0.62	0.098	2.58	11.29	0.082	2.17	9.49	0.00745	0.20	0.86	4.0	0.02	0.08
Plant 4 Heaters																						
S036	Regen Gas Heater	9.7	84,972	961	10,097	88	8,760	0.0054	0.05	0.23	0.098	0.95	4.17	0.082	0.80	3.50	0.00745	0.07	0.32	4.0	0.01	0.03
S037	Cryo HMO Heater	26.3	230,388	961	27,377	240	8,760	0.0054	0.14	0.62	0.098	2.58	11.29	0.082	2.17	9.49	0.00745	0.20	0.86	4.0	0.02	0.08
Plant 5 Heaters																						
S040	Regen Gas Heater	19.28	168,893	961	20,069	176	8,760	0.0054	0.10	0.46	0.098	1.89	8.28	0.082	1.59	6.95	0.00745	0.14	0.63	4.0	0.01	0.06
S041	Cryo HMO Heater	54.67	478,909	961	56,908	499	8,760	0.0054	0.29	1.29	0.098	5.36	23.48	0.082	4.50	19.72	0.00745	0.41	1.78	4.0	0.04	0.17
Plant 6 Heaters																						
S044	Regen Gas Heater	9.7	84,972	961	10,097	88	8,760	0.0054	0.05	0.23	0.098	0.95	4.17	0.082	0.80	3.50	0.00745	0.07	0.32	4.0	0.01	0.03
S045	Cryo HMO Heater	26.3	230,388	961	27,377	240	8,760	0.0054	0.14	0.62	0.098	2.58	11.29	0.082	2.17	9.49	0.00745	0.20	0.86	4.0	0.02	0.08

HOT OIL AND PLANT HEATERS POTENTIAL TO EMIT

AIR PERMIT CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID	Description	Maximum Hourly Heat Input (MMBtu/hr)	Maximum Annual Heat Input (MMBtu/yr)	Fuel Lower Heating Value (Btu/scf)	Maximum Hourly Fuel Use (scf/hr)	Maximum Annual Fuel Use (MMscf/yr)	Annual Operating Hours (hr/yr)	VOC			NO_X			CO			PM[d]			SO_2[e]		
								Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor[a] (lb/MMBtu)	PTE Hourly[b] (lb/hr)	PTE Annual[c] (T/yr)	Emission Factor (ppm S)	PTE Hourly (lb/hr)	PTE Annual[c] (T/yr)
Plant 7 Heaters																						
S048	Regen Gas Heater	9.7	84,972	961	10,097	88	8,760	0.0054	0.05	0.23	0.098	0.95	4.17	0.082	0.80	3.50	0.00745	0.07	0.32	4.0	0.01	0.03
S049	Cryo HMO Heater	26.3	230,388	961	27,377	240	8,760	0.0054	0.14	0.62	0.098	2.58	11.29	0.082	2.17	9.49	0.00745	0.20	0.86	4.0	0.02	0.08

[a] CO and VOC emission factors for Emission Unit ID S001 are based on vendor commitment, and NO_X emission factor is based on performance data. CO and NO_X emission factors for Emission Unit IDs S016 through S019, S052 and S053 are from vendor commitments. All other emission factors are from AP-42 Table 1.4-2 (dated 7/98), converted to lb/MMBtu by dividing by 1,020 Btu/scf.

[b] An hourly VOC emission calculation example for Unit ID S001 follows:

VOC (lb/hr) = (Maximum Heat Input, MMBtu/hr)*(Emission Factor, lb/MMBtu)

VOC (lb/hr) = (216.70 MMBtu/hr)*(0.0017 lb/MMBtu)

VOC (lb/hr) = 0.37 lb/hr VOC

[c] An annual VOC emission calculation example for Unit ID S001 follows:

VOC (T/yr) = (Hourly PTE, lb/hr)*(Annual Operating Hours, hr/yr)/(2,000 lb/T)

VOC (T/yr) = (0.37 lb/hr)*(8,760 hr/yr)/(2,000 lb/T)

VOC (T/yr) = 1.61 T/yr VOC

[d] All PM is assumed to be less than 2.5 microns in diameter per footnote "c" of AP-42 Table 1.4-2.

[e] A material balance approach was used to estimate the SO_2 emission rates using the maximum sulfur concentration in the natural gas.

An example calculation for hourly PTE SO_2 from Unit ID S001 follows:

SO_2 (lb/hr) = (Maximum Heat Input, MMBtu/hr)/(Fuel Heating Value, Btu/scf)*(Sulfur Content, ppm)*(1 lb-mol/379 scf)*(64.06 lb SO_2/lb-mol S)

SO_2 (lb/hr) = (216.70 MMBtu/hr)/(961 Btu/scf)*(4.0 lb-mol S/MMlb-mol gas)*(1 lb-mol/379 scf)*(64.06 lb SO2/lb-mol S)

= 0.15 lb/hr SO_2

COMBUSTION SOURCES POTENTIAL TO EMIT (SPECIATED)

AIR PERMIT CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

				PROJECT-AFFECTED OPERATIONS													
				Hot Oil Heater S016, S017, S018, S019, S052, S053		Hot Oil Heater S001		Regen Gas Heater S012, S024, S036, S044, S048		Cryo HMO Heater S013, S026, S037, S045, S049		Regen Gas Heater S040		Cryo HMO Heater S041		Stabilizer Heater S056	
	Emission Factor			Emission Rate, Per Heater		Emission Rate, Per Heater		Emission Rate, Per Heater		Emission Rate, Per Heater		Emission Rate, Per Heater		Emission Rate, Per Heater		Emission Rate, Per Heater	
	AP-42 Section 1.4 07/98 - Natural Gas Combustion - Heaters			Hourly[d]	Annual[e]	Hourly[d]	Annual[e]	Hourly[d]	Annual[e]	Hourly[d]	Annual[e]	Hourly[d]	Annual[e]	Hourly[d]	Annual[e]	Hourly[d]	Annual[e]
Pollutant	(lb/10^6scf)	(lb/MMBtu)[c]	Rating	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)
Number of Units				1		1		1		1		1		1		1	
Maximum Heat Input, MMBtu/hr:				61.6		216.7		9.7		26.3		19.3		54.7		10.1	
Maximum Operating Hours, hrs/yr:				8,760		8,760		8,760		8,760		8,760		8,760		8,760	
Engine Rating, hp:																	
VOC Emission Rate (Vendor Data)				0.33		0.37		0.05		0.14		0.10		0.29		0.05	
VOC Emission Rate (AP-42)	5.50E+00	5.39E-03	C	0.33		1.17		0.05		0.14		0.10		0.29		0.05	
Ratio Applied to HAPs Factor [b]				100.0%		31.5%		100.0%		100.0%		100.0%		100.0%		100.0%	
Formaldehyde Emission Rate (Vendor Data)																	
Formaldehyde Emission Rate (AP-42)																	
Ratio Applied to Acetaldehyde Factor:																	
1,1,2,2-Tetrachloroethane				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,1,2-Trichloroethane				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,3-Butadiene				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,3-Dichloropropene				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2-Methylnaphthalene	2.40E-05	2.35E-08	D	1.45E-06	6.35E-06	1.61E-06	7.04E-06	2.28E-07	1.00E-06	6.19E-07	2.71E-06	4.54E-07	1.99E-06	1.29E-06	5.63E-06	2.37E-07	1.04E-06
2,2,4-Trimethylpentane				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	E	9.66E-07	4.23E-06	1.07E-06	4.69E-06	1.52E-07	6.66E-07	4.13E-07	1.81E-06	3.02E-07	1.32E-06	8.58E-07	3.76E-06	1.58E-07	6.93E-07
[a] Acenaphthene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
[a] Acenaphthylene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
Acetaldehyde				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acrolein				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
[a] Anthracene	2.40E-06	2.35E-09	E	1.45E-07	6.35E-07	1.61E-07	7.04E-07	2.28E-08	1.00E-07	6.19E-08	2.71E-07	4.54E-08	1.99E-07	1.29E-07	5.63E-07	2.37E-08	1.04E-07
[a] Benz(a)anthracene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
Benzene	2.10E-03	2.06E-06	B	1.27E-04	5.55E-04	1.41E-04	6.16E-04	2.00E-05	8.75E-05	5.41E-05	2.37E-04	3.97E-05	1.74E-04	1.13E-04	4.93E-04	2.08E-05	9.10E-05
[a] Benzo(a)pyrene	1.20E-06	1.18E-09	E	7.24E-08	3.17E-07	8.04E-08	3.52E-07	1.14E-08	5.00E-08	3.09E-08	1.36E-07	2.27E-08	9.93E-08	6.43E-08	2.82E-07	1.19E-08	5.20E-08
[a] Benzo(b)flouoranthene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
[a] Benzo(e)pyrene				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
[a] Benzo(g,h,i)perylene	1.20E-06	1.18E-09	E	7.24E-08	3.17E-07	8.04E-08	3.52E-07	1.14E-08	5.00E-08	3.09E-08	1.36E-07	2.27E-08	9.93E-08	6.43E-08	2.82E-07	1.19E-08	5.20E-08
[a] Benzo(k)fluoranthene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
Biphenyl				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Carbon Tetrachloride				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chlorobenzene				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chloroform				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
[a] Chrysene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
[a] Dibenzo(a,h)anthracene	1.20E-06	1.18E-09	E	7.24E-08	3.17E-07	8.04E-08	3.52E-07	1.14E-08	5.00E-08	3.09E-08	1.36E-07	2.27E-08	9.93E-08	6.43E-08	2.82E-07	1.19E-08	5.20E-08
Dichlorobenzene	1.20E-03	1.18E-06	E	7.24E-05	3.17E-04	8.04E-05	3.52E-04	1.14E-05	5.00E-05	3.09E-05	1.36E-04	2.27E-05	9.93E-05	6.43E-05	2.82E-04	1.19E-05	5.20E-05
Ethylbenzene				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylene Dibromide				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
[a] Fluoranthene	3.00E-06	2.94E-09	E	1.81E-07	7.93E-07	2.01E-07	8.80E-07	2.85E-08	1.25E-07	7.74E-08	3.39E-07	5.67E-08	2.48E-07	1.61E-07	7.04E-07	2.97E-08	1.30E-07
[a] Fluorene	2.80E-06	2.75E-09	E	1.69E-07	7.40E-07	1.88E-07	8.21E-07	2.66E-08	1.17E-07	7.22E-08	3.16E-07	5.29E-08	2.32E-07	1.50E-07	6.57E-07	2.77E-08	1.21E-07
Formaldehyde	7.50E-02	7.35E-05	B	4.53E-03	1.98E-02	5.02E-03	2.20E-02	7.13E-04	3.12E-03	1.93E-03	8.47E-03	1.42E-03	6.21E-03	4.02E-03	1.76E-02	7.42E-04	3.25E-03
n-Hexane (<10 MMBtu/hr) [f]	6.30E-03	6.18E-06						5.99E-05	2.62E-04								
n-Hexane (10 - 100 MMBtu/hr) [f]	4.60E-03	4.51E-06		2.78E-04	1.22E-03					1.19E-04	5.20E-04	8.69E-05	3.81E-04	2.47E-04	1.08E-03	4.55E-05	1.99E-04
n-Hexane (>100 MMBtu/hr) [f]	1.30E-03	1.27E-06				8.71E-05	3.81E-04										
[a] Indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	E	1.09E-07	4.76E-07	1.21E-07	5.28E-07	1.71E-08	7.50E-08	4.64E-08	2.03E-07	3.40E-08	1.49E-07	9.65E-08	4.23E-07	1.78E-08	7.80E-08
Methanol				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Methylene Chloride				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
[a] Naphthalene	3.00E-04	2.94E-07	E	1.81E-05	7.93E-05	2.01E-05	8.80E-05	2.85E-06	1.25E-05	7.74E-06	3.39E-05	5.67E-06	2.48E-05	1.61E-05	7.04E-05	2.97E-06	1.30E-05
PAHs	3.46E-04	3.40E-07		2.09E-05	9.16E-05	2.32E-05	1.02E-04	3.29E-06	1.44E-05	8.93E-06	3.91E-05	6.55E-06	2.87E-05	1.86E-05	8.13E-05	3.43E-06	1.50E-05
[a] Phenanathrene	1.70E-05	1.67E-08	D	1.03E-06	4.50E-06	1.14E-06	4.99E-06	1.62E-07	7.08E-07	4.38E-07	1.92E-06	3.21E-07	1.41E-06	9.11E-07	3.99E-06	1.68E-07	7.37E-07
Phenol				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
[a] Pyrene	5.00E-06	4.90E-09	E	3.02E-07	1.32E-06	3.35E-07	1.47E-06	4.75E-08	2.08E-07	1.29E-07	5.65E-07	9.45E-08	4.14E-07	2.68E-07	1.17E-06	4.95E-08	2.17E-07
Tetrachloroethane				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene	3.40E-03	3.33E-06	C	2.05E-04	8.99E-04	2.28E-04	9.97E-04	3.23E-05	1.42E-04	8.77E-05	3.84E-04	6.43E-05	2.81E-04	1.82E-04	7.98E-04	3.36E-05	1.47E-04
Vinyl Chloride				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xylene				0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Arsenic	2.00E-04	1.96E-07	E	1.21E-05	5.29E-05	1.34E-05	5.87E-05	1.90E-06	8.33E-06	5.16E-06	2.26E-05	3.78E-06	1.66E-05	1.07E-05	4.70E-05	1.98E-06	8.67E-06
Barium	4.40E-03	4.31E-06	D	2.66E-04	1.16E-03	2.95E-04	1.29E-03	4.18E-05	1.83E-04	1.13E-04	4.97E-04	8.32E-05	3.64E-04	2.36E-04	1.03E-03	4.35E-05	1.91E-04
Beryllium	1.20E-05	1.18E-08	E	7.24E-07	3.17E-06	8.04E-07	3.52E-06	1.14E-07	5.00E-07	3.09E-07	1.36E-06	2.27E-07	9.93E-07	6.43E-07	2.82E-06	1.19E-07	5.20E-07
Cadmium	1.10E-03	1.08E-06	D	6.64E-05	2.91E-04	7.37E-05	3.23E-04	1.05E-05	4.58E-05	2.84E-05	1.24E-04	2.08E-05	9.11E-05	5.90E-05	2.58E-04	1.09E-05	4.77E-05
Chromium	1.40E-03	1.37E-06	D	8.45E-05	3.70E-04	9.38E-05	4.11E-04	1.33E-05	5.83E-05	3.61E-05	1.58E-04	2.65E-05	1.16E-04	7.50E-05	3.29E-04	1.38E-05	6.07E-05
Cobalt	8.40E-05	8.24E-08	D	5.07E-06	2.22E-05	5.63E-06	2.46E-05	7.99E-07	3.50E-06	2.17E-06	9.49E-06	1.59E-06	6.95E-06	4.50E-06	1.97E-05	8.31E-07	3.64E-06
Copper	8.50E-04	8.33E-07	C	5.13E-05	2.25E-04	5.69E-05	2.49E-04	8.08E-06	3.54E-05	2.19E-05	9.60E-05	1.61E-05	7.04E-05	4.56E-05	2.00E-04	8.41E-06	3.68E-05
Lead	5.00E-04	4.90E-07	D	3.02E-05	1.32E-04	3.35E-05	1.47E-04	4.75E-06	2.08E-05	1.29E-05	5.65E-05	9.45E-06	4.14E-05	2.68E-05	1.17E-04	4.95E-06	2.17E-05
Manganese	3.80E-04	3.73E-07	D	2.29E-05	1.00E-04	2.55E-05	1.11E-04	3.61E-06	1.58E-05	9.80E-06	4.29E-05	7.18E-06	3.15E-05	2.04E-05	8.92E-05	3.76E-06	1.65E-05
Mercury	2.60E-04	2.55E-07	D	1.57E-05	6.88E-05	1.74E-05	7.63E-05	2.47E-06	1.08E-05	6.70E-06	2.94E-05	4.91E-06	2.15E-05	1.39E-05	6.10E-05	2.57E-06	1.13E-05
Molybdenum	1.10E-03	1.08E-06	D	6.64E-05	2.91E-04	7.37E-05	3.23E-04	1.05E-05	4.58E-05	2.84E-05	1.24E-04	2.08E-05	9.11E-05	5.90E-05	2.58E-04	1.09E-05	4.77E-05
Nickel	2.10E-03	2.06E-06	C	1.27E-04	5.55E-04	1.41E-04	6.16E-04	2.00E-05	8.75E-05	5.41E-05	2.37E-04	3.97E-05	1.74E-04	1.13E-04	4.93E-04	2.08E-05	9.10E-05
Selenium	2.40E-05	2.35E-08	E	1.45E-06	6.35E-06	1.61E-06	7.04E-06	2.28E-07	1.00E-06	6.19E-07	2.71E-06	4.54E-07	1.99E-06	1.29E-06	5.63E-06	2.37E-07	1.04E-06
Vanadium	2.30E-03	2.25E-06	D	1.39E-04	6.08E-04	1.54E-04	6.75E-04	2.19E-05	9.58E-05	5.93E-05	2.60E-04	4.35E-05	1.90E-04	1.23E-04	5.40E-04	2.28E-05	9.97E-05
Zinc	2.90E-02	2.84E-05	E	1.75E-03	7.67E-03	1.94E-03	8.51E-03	2.76E-04	1.21E-03	7.48E-04	3.28E-03	5.48E-04	2.40E-03	1.55E-03	6.81E-03	2.87E-04	1.26E-03
AP-42 Natural Gas Heating Value	1,020 Btu/scf (HHV)																

(a) PAH, so summed in PAH total.

(b) AP-42 emission factors have been adjusted by the ratio of the proposed VOC emission rate to the VOC emission rate calculated with AP-42 emission factors.

(c) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (HHV Btu/scf).

(d) Hourly Emission Rate (lb/hr) = [Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu)] * VOC Ratio

(e) Annual Emission Rate (T/yr) = (Hourly Emission Rate, lb/hr) * (Annual Hours of Operation, hr/yr) / (2,000 lb/T)

(f) Hexane emission factors taken from Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors guidance document for natural gas combustion.

FUGITIVE AREA 1 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component/Stream	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC Content (%)	Maximum CO_2 Content (%)	Maximum CH_4 Content (%)	Uncontrolled PTE VOC Hourly [b] (lb/hr)	Uncontrolled PTE VOC Annual [c] (T/yr)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual [c] (T/yr)
Valves														
Gas (Natural Gas)	3,000	0.0045	8,760	20%	1%	70%	5.9525	26.0718	96%	0.2381	1.0429	0.0521	3.6501	91.30
Light Liquid	3,194	0.0025	8,760	100%	0%	0%	17.6039	77.1050	95%	0.8802	3.8553	0.0000	0.0000	0.00
Heavy Liquid	65	0.0000084	8,760	100%	0%	0%	0.0012	0.0053	0%	0.0012	0.0053	0.0000	0.0000	0.00
Flanges														
Gas (Natural Gas)	458	0.00039	8,760	20%	1%	70%	0.0788	0.3450	0%	0.0788	0.3450	0.0172	1.2074	30.20
Light Liquid	7	0.00011	8,760	100%	0%	0%	0.0017	0.0074	0%	0.0017	0.0074	0.0000	0.0000	0.00
Relief Valves														
Gas (Natural Gas)	62	0.0088	8,760	20%	1%	70%	0.2406	1.0537	0%	0.2406	1.0537	0.0527	3.6879	92.25
Light Liquid	34	0.0075	8,760	100%	0%	0%	0.5622	2.4623	0%	0.5622	2.4623	0.0000	0.0000	0.00
Compressor Seals														
Gas (Natural Gas)	17	0.0088	8,760	20%	1%	70%	0.0660	0.2889	0%	0.0660	0.2889	0.0144	1.0112	25.29
Pump Seals [d]														
Light Liquid	38	0.013	8,760	100%	0%	0%	1.0891	4.7702	88%	0.1307	0.5724	0.0000	0.0000	0.00
Heavy Liquid	3	0.00051	8,760	100%	0%	0%	0.0034	0.0148	0%	0.0034	0.0148	0.0000	0.0000	0.00
Connectors [e]														
Gas (Natural Gas)	10,124	0.0002	8,760	20%	1%	70%	0.8928	3.9104	81%	0.1696	0.7430	0.0371	2.6004	65.05
Light Liquid	10,656	0.00021	8,760	100%	0%	0%	4.9334	21.6083	81%	0.9373	4.1056	0.0000	0.0000	0.00
Closed Vent System - Valves [f]														
Gas (Natural Gas)	281	0.0045	8,760	20%	1%	70%	0.5575	2.4421	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	13	0.0025	8,760	100%	0%	0%	0.0717	0.3138	100%	0.0000	0.0000	0.0000	0.0000	0.00
Closed Vent System - Flanges [f]														
Gas (Natural Gas)	406	0.00039	8,760	20%	1%	70%	0.0698	0.3058	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	8	0.0001	8,760	100%	0%	0%	0.0018	0.0077	100%	0.0000	0.0000	0.0000	0.0000	0.00
Closed Vent System - Connectors [f]														
Gas (Natural Gas)	275	0.0002	8,760	20%	1%	70%	0.0243	0.1062	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	33	0.00021	8,760	100%	0%	0%	0.0153	0.0669	100%	0.0000	0.0000	0.0000	0.0000	0.00
Closed Vent System - Relief Valves [f]														
Gas (Natural Gas)	60	0.0088	8,760	20%	1%	70%	0.2328	1.0197	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	1	0.0075	8,760	100%	0%	0%	0.0165	0.0724	100%	0.0000	0.0000	0.0000	0.0000	0.00
									TOTAL:	**3.31**	**14.50**	**0.17**	**12.16**	**304.10**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500

[b] Hourly VOC emissions are calculated as follows:

(3,000 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (100% VOC) * (100% - 96% reduction credit) = 0.2381 lb/hr

[c] Annual VOC emission rates are calculated as follows:

(0.2381 lb/hr) * (8,760 hr/yr) / (2,000 lb/T) = 1.0429 T/yr

[d] Leakless pumps are not included in the pump count.

[e] Sampling connections are included in this category, because all sampling utilizes inline analyzers (i.e., closed loop sampling), such that additional emissions per sample do not occur.

[f] Closed vent system gas and light liquid components are vented to the Flare S004A. Therefore, any leaks are routed to flare, and not to atmosphere as fugitive emissions (i.e., 100% control is taken). The Flare PTE calculation includes these potential leaks.

FUGITIVE AREA 1 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	PTE Total VOC		Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Toluene		Ethylbenzene		Xylene	
Stream	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly (lb/hr)**	**% in Stream**	**Hourly (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**
Gas (Natural Gas)	**0.7930**	**3.4734**	65.91%	0.5227	18.09%	0.1435	52.34%	0.4150	17.27%	0.1369	11.86%	0.0941	4.87%	0.0386	6.35%	0.0503	1.42%	0.0113	3.02%	0.0240	0.03%	0.0002	1.84%	0.0146	0.95%	0.0076	0.04%	0.0003	0.00%	0.0000	0.01%	0.0001
Light Liquid	**2.5121**	**11.0030**	0.02%	0.0005	0.79%	0.0199	99.15%	2.4907	0.18%	0.0045	0.67%	0.0168	0.00%	0.0000	0.01%	0.0002	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Water/Oil	**0.0000**	**0.0000**	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Heavy Liquid	**0.0046**	**0.0201**	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	100.00%	0.0046	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**3.31**			**0.5232**		**0.1634**		**2.9057**		**0.1414**		**0.1108**		**0.0386**		**0.0505**		**0.0113**		**0.0240**		**0.0002**		**0.0146**		**0.0121**		**0.0003**		**0.0000**		**0.0001**
Total (T/yr):	**14.50**			**2.2918**		**0.7157**		**12.7269**		**0.6193**		**0.4854**		**0.1691**		**0.2212**		**0.0495**		**0.1050**		**0.0010**		**0.0639**		**0.0532**		**0.0014**		**0.0000**		**0.0005**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.7930 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.4150 lb/hr Propane

FUGITIVE AREA 1 CLOSED VENT SYSTEM EQUIPMENT LEAKS TO FLARE

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	Uncontrolled VOC to Flare			Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Ethylbenzene		Toluene		Xylene	
Stream	**% in Stream**	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly[a] (lb/hr)**	**% in Stream**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**
Gas (Natural Gas)	20%	0.8844	3.8738	65.91%	2.9148	18.09%	0.8000	52.34%	0.4629	17.27%	0.1527	11.86%	0.1049	4.87%	0.0431	6.35%	0.0561	1.42%	0.0126	3.02%	0.0267	0.03%	0.0003	1.84%	0.0163	0.95%	0.0084	0.00%	0.0000	0.04%	0.0004	0.01%	0.0001
Light Liquid	100%	0.1052	0.4609	0.02%	0.0000	0.79%	0.0008	99.15%	0.1043	0.18%	0.0002	0.67%	0.0007	0.00%	0.0000	0.01%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Water/Oil	100%	0.0000	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Heavy Liquid	100%	0.0000	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):		**0.99**			**2.9148**		**0.8008**		**0.5672**		**0.1529**		**0.1056**		**0.0431**		**0.0562**		**0.0126**		**0.0267**		**0.0003**		**0.0163**		**0.0084**		**0.0000**		**0.0004**		**0.0001**
Total (T/yr):		**4.33**			**12.7669**		**3.5077**		**2.4844**		**0.6696**		**0.4626**		**0.1886**		**0.2460**		**0.0550**		**0.1172**		**0.0011**		**0.0713**		**0.0369**		**0.0000**		**0.0015**		**0.0005**

[a] An example calculation of the emission rate to flare for methane follows:

Methane (lb/hr) = (Uncontrolled VOC to Flare, lb/hr) / (% VOC in Stream) * (% Methane in Stream)

Methane (lb/hr) = (0.8844 lb/hr VOC) / (20% VOC) * (65.91% Methane)

Methane (lb/hr) = 2.9148 lb/hr Methane

[b] An example calculation of the emission rate to flare for VOC constituents follows:

Propane (lb/hr) = (Uncontrolled VOC to Flare, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.8844 lb/hr VOC) * (52.34% Propane)

Propane (lb/hr) = 0.4629 lb/hr Propane

FUGITIVE AREA 2 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component/Stream	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC Content (%)	Maximum CO_2 Content (%)	Maximum CH_4 Content (%)	Uncontrolled PTE VOC Hourly [b] (lb/hr)	Uncontrolled PTE VOC Annual [c] (T/yr)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual [c] (T/yr)
Valves														
Gas (Natural Gas)	2,546	0.0045	8,760	20%	1%	70%	5.0517	22.1263	96%	0.2021	0.8851	0.0443	3.0977	77.49
Light Liquid	4,123	0.0025	8,760	100%	0%	0%	22.7214	99.5196	95%	1.1361	4.9760	0.0000	0.0000	0.00
Flanges														
Gas (Natural Gas)	1653	0.00039	8,760	20%	1%	70%	0.2842	1.2446	0%	0.2842	1.2446	0.0622	4.3562	108.97
Light Liquid	2117	0.00011	8,760	100%	0%	0%	0.5133	2.2481	0%	0.5133	2.2481	0.0000	0.0000	0.00
Relief Valves														
Gas (Natural Gas)	90	0.0088	8,760	20%	1%	70%	0.3492	1.5295	0%	0.3492	1.5295	0.0765	5.3534	133.91
Light Liquid	43	0.0075	8,760	100%	0%	0%	0.7027	3.0779	0%	0.7027	3.0779	0.0000	0.0000	0.00
Compressor Seals														
Gas (Natural Gas)	10	0.0088	8,760	20%	1%	0%	0.0388	0.1699	0%	0.0388	0.1699	0.0085	0.0000	0.01
Pump Seals [d]														
Light Liquid	54	0.013	8,760	100%	0%	0%	1.5476	6.7787	88%	0.1857	0.8134	0.0000	0.0000	0.00
Connectors [e]														
Gas (Natural Gas)	12,609	0.0002	8,760	20%	1%	70%	1.1119	4.8700	81%	0.2113	0.9253	0.0463	3.2386	81.01
Light Liquid	14,331	0.00021	8,760	100%	0%	0%	6.6348	29.0605	81%	1.2606	5.5215	0.0000	0.0000	0.00
Open-Ended Lines														
Gas (Natural Gas)	527	0.002	8,760	20%	1%	70%	0.4647	2.0355	0%	0.4647	2.0355	0.1018	7.1244	178.21
Light Liquid	834	0.0014	8,760	100%	0%	0%	2.5741	11.2746	0%	2.5741	11.2746	0.0000	0.0000	0.00
Closed Vent System - Valves [f]														
Gas (Natural Gas)	74	0.0045	8,760	20%	1%	70%	0.1468	0.6431	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	34	0.0025	8,760	100%	0%	0%	0.1874	0.8208	100%	0.0000	0.0000	0.0000	0.0000	0.00
Closed Vent System - Flanges [f]														
Gas (Natural Gas)	191	0.00039	8,760	20%	1%	70%	0.0328	0.1439	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	70	0.0001	8,760	100%	0%	0%	0.0154	0.0676	100%	0.0000	0.0000	0.0000	0.0000	0.00
Closed Vent System - Connectors [f]														
Gas (Natural Gas)	107	0.0002	8,760	20%	1%	70%	0.0094	0.0413	100%	0.0000	0.0000	0.0000	0.0000	0.00
Light Liquid	29	0.00021	8,760	100%	0%	0%	0.0134	0.0588	100%	0.0000	0.0000	0.0000	0.0000	0.00
									TOTAL:	**7.92**	**34.70**	**0.34**	**23.17**	**579.60**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500

[b] Hourly VOC emissions are calculated as follows:

(2,546 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (100% VOC) * (100% - 96% reduction credit) = 0.2021 lb/hr

[c] Annual VOC emission rates are calculated as follows:

(0.2021 lb/hr) * (8,760 hr/yr) / (2,000 lb/T) = 0.8851 T/yr

[d] Leakless pumps are not included in the pump count.

[e] Sampling connections are included in this category, because all sampling utilizes inline analyzers (i.e., closed loop sampling), such that additional emissions per sample do not occur.

[f] Closed vent system gas and light liquid components are vented to the Flare S004A. Therefore, any leaks are routed to flare, and not to atmosphere as fugitive emissions (i.e., 100% control is taken). The Flare PTE calculation includes these potential leaks.

FUGITIVE AREA 2 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Stream	PTE Total VOC Hourly (lb/hr)	PTE Total VOC Annual (T/yr)	Methane % in Stream	Methane Hourly (lb/hr)	Ethane % in Stream	Ethane Hourly (lb/hr)	Propane % in VOC	Propane Hourly[a] (lb/hr)	N-Butane % in VOC	N-Butane Hourly[a] (lb/hr)	Isobutane % in VOC	Isobutane Hourly[a] (lb/hr)	N-Pentane % in VOC	N-Pentane Hourly[a] (lb/hr)	Isopentane % in VOC	Isopentane Hourly[a] (lb/hr)	n-Hexane % in VOC	n-Hexane Hourly[a] (lb/hr)	Other Hexanes % in VOC	Other Hexanes Hourly[a] (lb/hr)	Benzene % in VOC	Benzene Hourly[a] (lb/hr)	Heptane % in VOC	Heptane Hourly[a] (lb/hr)	Octane+ % in VOC	Octane+ Hourly[a] (lb/hr)	Toluene % in VOC	Toluene Hourly[a] (lb/hr)	Ethylbenzene % in VOC	Ethylbenzene Hourly[a] (lb/hr)	Xylene % in VOC	Xylene Hourly[a] (lb/hr)
Gas (Natural Gas)	**1.5502**	**6.7900**	65.91%	1.0218	18.09%	0.2805	52.34%	0.8113	17.27%	0.2677	11.86%	0.1839	4.87%	0.0755	6.35%	0.0984	1.42%	0.0220	3.02%	0.0469	0.03%	0.0004	1.84%	0.0285	0.95%	0.0148	0.04%	0.0006	0.00%	0.0000	0.01%	0.0002
Light Liquid	**6.3725**	**27.9116**	0.02%	0.0013	0.79%	0.0506	99.15%	6.3181	0.18%	0.0114	0.67%	0.0425	0.00%	0.0000	0.01%	0.0004	0.00%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Water/Oil	**0.0000**	**0.0000**	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Heavy Liquid	**0.0000**	**0.0000**	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**7.92**			**1.0231**		**0.3310**		**7.1294**		**0.2790**		**0.2264**		**0.0755**		**0.0988**		**0.0221**		**0.0469**		**0.0004**		**0.0285**		**0.0148**		**0.0006**		**0.0000**		**0.0002**
Total (T/yr):	**34.70**			**4.4814**		**1.4498**		**31.2269**		**1.2221**		**0.9917**		**0.3306**		**0.4329**		**0.0969**		**0.2054**		**0.0019**		**0.1249**		**0.0647**		**0.0027**		**0.0000**		**0.0010**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (1.5502 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.8113 lb/hr Propane

FUGITIVE AREA 2 CLOSED VENT SYSTEM EQUIPMENT LEAKS TO FLARE

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	Uncontrolled VOC to Flare			Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Ethylbenzene		Toluene		Xylene	
Stream	**% in Stream**	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly[a] (lb/hr)**	**% in Stream**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**	**% in VOC**	**Hourly[b] (lb/hr)**
Gas (Natural Gas)	20%	0.1891	0.8283	65.91%	0.6232	18.09%	0.1711	52.34%	0.0990	17.27%	0.0326	11.86%	0.0224	4.87%	0.0092	6.35%	0.0120	1.42%	0.0027	3.02%	0.0057	0.03%	0.0001	1.84%	0.0035	0.95%	0.0018	0.00%	0.0000	0.04%	0.0001	0.01%	0.0000
Light Liquid	100%	0.2163	0.9472	0.02%	0.0000	0.79%	0.0017	99.15%	0.2144	0.18%	0.0004	0.67%	0.0014	0.00%	0.0000	0.01%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Water/Oil	100%	0.0000	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Heavy Liquid	100%	0.0000	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):		**0.41**			**0.6233**		**0.1728**		**0.3134**		**0.0330**		**0.0239**		**0.0092**		**0.0120**		**0.0027**		**0.0057**		**0.0001**		**0.0035**		**0.0018**		**0.0000**		**0.0001**		**0.00003**
Total (T/yr):		**1.78**			**2.7300**		**0.7568**		**1.3726**		**0.1447**		**0.1046**		**0.0403**		**0.0526**		**0.0118**		**0.0251**		**0.0002**		**0.0152**		**0.0079**		**0.0000**		**0.0003**		**0.0001**

[a] An example calculation of the emission rate to flare for methane follows:

Methane (lb/hr) = (Uncontrolled VOC to Flare, lb/hr) / (% VOC in Stream) * (% Methane in Stream)

Methane (lb/hr) = (0.1891 lb/hr VOC) / (20% VOC) * (65.91% Methane)

Methane (lb/hr) = 0.6232 lb/hr Methane

[b] An example calculation of the emission rate to flare for VOC constituents follows:

Propane (lb/hr) = (Uncontrolled VOC to Flare, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.1891 lb/hr VOC) * (52.34% Propane)

Propane (lb/hr) = 0.0990 lb/hr Propane

CLOSED VENT SYSTEM FEED RATE TO FLARE

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Point ID	Flare	P004A

Component	Component LHV (Btu/lb)	Uncontrolled Emissions From Area 2 Closed Vent System Leaks[a] Hourly (lb/hr)	Uncontrolled Emissions From Area 2 Closed Vent System Leaks[a] Annual (T/yr)	Flare DRE (%)	Potential to Emit[d] Hourly (lb/hr)	Potential to Emit[d] Annual (T/yr)
Methane	21,502	0.6233	2.7300	99%	0.0062	0.0273
Ethane	20,416	0.1728	0.7568	99%	0.0017	0.0076
Propane	19,929	0.3134	1.3726	98%	0.0063	0.0275
i-Butane	19,614	0.0239	0.1046	98%	0.0005	0.0021
n-Butane	19,665	0.0330	0.1447	98%	0.0007	0.0029
i-Pentane	19,451	0.0120	0.0526	98%	0.0002	0.0011
n-Pentane	19,499	0.0092	0.0403	98%	0.0002	0.0008
n-Hexane	19,391	0.0027	0.0118	98%	0.0001	0.0002
Other Hexanes	19,147	0.0057	0.0251	98%	0.0001	0.0005
Benzene	18,000	0.0001	0.0002	98%	0.0000	0.0000
Heptane	19,163	0.0035	0.0152	98%	0.0001	0.0003
Octane	19,104	0.0018	0.0079	98%	0.0000	0.0002
Toluene	18,501	0.0001	0.0003	98%	0.0000	0.0000
Ethlybenzene	17,780	0.0000	0.0000	98%	0.0000	0.0000
Xylene	18,410	0.0000	0.0001	98%	0.0000	0.0000
TOTAL:	**20,785**	**1.20**	**5.26**		**0.02**	**0.07**
TOTAL VOC:		**0.41**	**1.78**		**0.01**	**0.04**
TOTAL HAPs:		**0.003**	**0.01**		**0.0001**	**0.0002**

Component	Component LHV (Btu/lb)	Uncontrolled Emissions From Area 1 Closed Vent System Leaks[b] Hourly (lb/hr)	Uncontrolled Emissions From Area 1 Closed Vent System Leaks[b] Annual (T/yr)	Uncontrolled Emissions from Cryo Plants Closed Vent Systems[c] Hourly (lb/hr)	Uncontrolled Emissions from Cryo Plants Closed Vent Systems[c] Annual (T/yr)	Flare DRE (%)	Potential to Emit[d] Hourly (lb/hr)	Potential to Emit[d] Annual (T/yr)
Methane	21,502	2.9148	12.7669	14.5741	63.8346	99%	0.1749	0.7660
Ethane	20,416	0.8008	3.5077	4.0042	17.5385	99%	0.0481	0.2105
Propane	19,929	0.5672	2.4844	2.8360	12.4218	98%	0.0681	0.2981
i-Butane	19,614	0.1056	0.4626	0.5281	2.3130	98%	0.0127	0.0555
n-Butane	19,665	0.1529	0.6696	0.7644	3.3482	98%	0.0183	0.0804
i-Pentane	19,451	0.0562	0.2460	0.2808	1.2298	98%	0.0067	0.0295
n-Pentane	19,499	0.0431	0.1886	0.2153	0.9430	98%	0.0052	0.0226
n-Hexane	19,391	0.0126	0.0550	0.0628	0.2750	98%	0.0015	0.0066
Other Hexanes	19,147	0.0267	0.1172	0.1337	0.5858	98%	0.0032	0.0141
Benzene	18,000	0.0003	0.0011	0.0013	0.0055	98%	0.0000	0.0001
Ethyl Mercaptan	20,416	0.0000	0.0000	0.0000	0.0000	98%	0.0000	0.0000
Heptane	19,163	0.0163	0.0713	0.0813	0.3563	98%	0.0020	0.0086
Octane	19,104	0.0084	0.0369	0.0421	0.1845	98%	0.0010	0.0044
Toluene	18,501	0.0004	0.0015	0.0018	0.0077	98%	0.0000	0.0002
Ethlybenzene	17,780	0.0000	0.0000	0.0000	0.0000	98%	0.0000	0.0000
Xylene	18,410	0.0001	0.0005	0.0006	0.0027	98%	0.0000	0.0001
TOTAL:	**20,951**	**4.71**	**20.61**	**23.53**	**103.05**		**0.34**	**1.50**
TOTAL VOC:		**0.99**	**4.33**	**4.95**	**21.67**		**0.12**	**0.52**
TOTAL HAPs:		**0.01**	**0.06**	**0.07**	**0.29**		**0.002**	**0.01**

[a] Please refer to the calculation sheet "Fug Area 2 Closed Vent System Equipment Leaks to Flare."

[b] Please refer to the calculation sheet "Fug Area 1 Closed Vent System Equipment Leaks to Flare."

[c] To account for the Closed Vent System on fugitive area 3, and proposed fugitive areas 4, 5, 6, and 7, the uncontrolled emissions from Area 1 have been multiplied by 5 to account for the additional cryo plants.

[d] An example calculation for Potential to Emit Ethane follows:

Ethane PTE (lb/hr) = (Uncontrolled PRV Equipment Leaks, lb/hr) * (1 - Flare DRE, wt%)

Ethane PTE (lb/hr) = (0.1728 lb/hr) * (1 - 99%)

Ethane PTE (lb/hr) = 0.0017

FUGITIVE AREA 3 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC (wt%)	Maximum CO_2 (wt%)	Maximum CH_4 (wt%)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual (T/yr)
Valves												
Gas Streams	1,605	0.0045	8,760	20%	1%	70%	96%	0.1274	0.5579	2.79E-02	1.95E+00	48.8474
Gas Stream (Propane)	34	0.0045	8,760	100%	0%	0%	96%	0.0135	0.0591	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	1,625	0.0025	8,760	100%	0%	0%	95%	0.4478	1.9614	0.00E+00	0.00E+00	0.0000
Relief Valves												
Gas Streams	52	0.0088	8,760	20%	1%	70%	0%	0.2018	0.8837	4.42E-02	3.09E+00	77.3713
Gas Stream (Propane)	9	0.0088	8,760	100%	0%	0%	0%	0.1746	0.7648	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	45	0.0075	8,760	100%	0%	0%	0%	0.7441	3.2590	0.00E+00	0.00E+00	0.0000
Compressor Seals												
Gas Streams	5	0.0088	8,760	20%	1%	70%	0%	0.0194	0.0850	4.25E-03	2.97E-01	7.4395
Gas Stream (Propane)	4	0.0088	8,760	100%	0%	0%	0%	0.0776	0.3399	0.00E+00	0.00E+00	0.0000
Pump Seals												
Light Liquid Stream	15	0.013	8,760	100%	0%	0%	88%	0.0516	0.2260	0.00E+00	0.00E+00	0.0000
Flanges												
Gas Streams	1,311	0.00039	8,760	20%	1%	70%	0%	0.2254	0.9874	4.94E-02	3.46E+00	86.4492
Gas Stream (Propane)	110	0.00039	8,760	100%	0%	0%	0%	0.0946	0.4143	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	846	0.00011	8,760	100%	0%	0%	0%	0.2052	0.8986	0.00E+00	0.00E+00	0.0000
Connectors												
Gas Streams	4,475	0.0002	8,760	20%	1%	70%	81%	0.0750	0.3284	1.64E-02	1.15E+00	28.7522
Gas Stream (Propane)	304	0.0002	8,760	100%	0%	0%	81%	0.0255	0.1115	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	6,976	0.00021	8,760	100%	0%	0%	81%	0.6136	2.6877	0.00E+00	0.00E+00	0.0000
							Gas Streams:	**0.6490**	**2.8425**	**0.1421**	**9.9487**	**248.8597**
							Gas Stream (Propane):	**0.3857**	**1.6896**	**0.0000**	**0.0000**	**0.0000**
							Light Liquid Stream:	**2.0623**	**9.0327**	**0.0000**	**0.0000**	**0.0000**
							TOTALS:	**3.10**	**13.56**	**0.14**	**9.95**	**248.86**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500 ppm.

[b] Hourly VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (20% VOC) * (100% - 96% reduction credit) = 0.1274 lb/hr

[c] Annual VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (8,760 hr/yr) * (20% VOC) * (100% - 96% reduction credit) / (2,000 lb/T) = 0.5579 T/yr

FUGITIVE AREA 3 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	PTE Total VOC		Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Toluene		Ethylbenzene		Xylene	
Stream	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly (lb/hr)**	**% in Stream**	**Hourly (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**
Gas (Natural Gas)	**0.6490**	**2.8425**	65.91%	0.4278	18.09%	0.1174	52.34%	0.3397	17.27%	0.1120	11.86%	0.0770	4.87%	0.0316	6.35%	0.0412	1.42%	0.0092	3.02%	0.0196	0.03%	0.0002	1.84%	0.0119	0.95%	0.0062	0.04%	0.0003	0.00%	0.0000	0.01%	0.0001
Gas (Propane)	**0.3857**	**1.6896**	0.02%	0.0001	0.79%	0.0031	99.15%	0.3825	0.18%	0.0007	0.67%	0.0026	0.00%	0.0000	0.01%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Light Liquid	**2.0623**	**9.0327**	0.02%	0.0004	0.79%	0.0164	99.15%	2.0446	0.18%	0.0037	0.67%	0.0138	0.00%	0.0000	0.01%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**3.10**			**0.4283**		**0.1368**		**2.7667**		**0.1164**		**0.0933**		**0.0316**		**0.0414**		**0.0093**		**0.0196**		**0.0002**		**0.0119**		**0.0062**		**0.0003**		**0.0000**		**0.0001**
Total (T/yr):	**13.56**			**1.8758**		**0.5993**		**12.1184**		**0.5099**		**0.4087**		**0.1384**		**0.1812**		**0.0406**		**0.0860**		**0.0008**		**0.0523**		**0.0271**		**0.0011**		**0.0000**		**0.0004**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.6490 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.3397 lb/hr Propane

FUGITIVE AREA 4 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC (wt%)	Maximum CO_2 (wt%)	Maximum CH_4 (wt%)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual (T/yr)
Valves												
Gas Streams	2,350	0.0045	8,760	20%	1%	70%	96%	0.1865	0.8169	4.08E-02	2.86E+00	71.5211
Gas Stream (Propane)	134	0.0045	8,760	100%	0%	0%	96%	0.0532	0.2329	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	1,625	0.0025	8,760	100%	0%	0%	95%	0.4478	1.9614	0.00E+00	0.00E+00	0.0000
Relief Valves												
Gas Streams	96	0.0088	8,760	20%	1%	70%	0%	0.3725	1.6315	8.16E-02	5.71E+00	142.8393
Gas Stream (Propane)	9	0.0088	8,760	100%	0%	0%	0%	0.1746	0.7648	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	45	0.0075	8,760	100%	0%	0%	0%	0.7441	3.2590	0.00E+00	0.00E+00	0.0000
Compressor Seals												
Gas Streams	5	0.0088	8,760	20%	1%	70%	0%	0.0194	0.0850	4.25E-03	2.97E-01	7.4395
Gas Stream (Propane)	23	0.0088	8,760	100%	0%	0%	0%	0.4462	1.9544	0.00E+00	0.00E+00	0.0000
Pump Seals												
Light Liquid Stream	17	0.013	8,760	100%	0%	0%	88%	0.0585	0.2561	0.00E+00	0.00E+00	0.0000
Flanges												
Gas Streams	1,871	0.00039	8,760	20%	1%	70%	0%	0.3217	1.4092	7.05E-02	4.93E+00	123.3765
Gas Stream (Propane)	110	0.00039	8,760	100%	0%	0%	0%	0.0946	0.4143	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	846	0.00011	8,760	100%	0%	0%	0%	0.2052	0.8986	0.00E+00	0.00E+00	0.0000
Connectors												
Gas Streams	7,570	0.0002	8,760	20%	1%	70%	81%	0.1268	0.5555	2.78E-02	1.94E+00	48.6377
Gas Stream (Propane)	525	0.0002	8,760	100%	0%	0%	81%	0.0440	0.1926	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	6,976	0.00021	8,760	100%	0%	0%	81%	0.6136	2.6877	0.00E+00	0.00E+00	0.0000
							Gas Streams:	**1.0270**	**4.4982**	**0.2249**	**15.7436**	**393.8142**
							Gas Stream (Propane):	**0.8126**	**3.5590**	**0.0000**	**0.0000**	**0.0000**
							Light Liquid Stream:	**2.0691**	**9.0628**	**0.0000**	**0.0000**	**0.0000**
							TOTALS:	**3.91**	**17.12**	**0.22**	**15.74**	**393.81**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500 ppm.

[b] Hourly VOC emission rates are calculated as follows:
(2,350 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (20% VOC) * (100% - 96% reduction credit) = 0.1865 lb/hr

[c] Annual VOC emission rates are calculated as follows:
(2,350 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (8,760 hr/yr) * (20% VOC) * (100% - 96% reduction credit) / (2,000 lb/T) = 0.8169 T/yr

FUGITIVE AREA 4 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	PTE Total VOC		Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Toluene		Ethylbenzene		Xylene	
Stream	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly (lb/hr)**	**% in Stream**	**Hourly (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**
Gas (Natural Gas)	**1.0270**	**4.4982**	65.91%	0.6769	18.09%	0.1858	52.34%	0.5375	17.27%	0.1773	11.86%	0.1218	4.87%	0.0500	6.35%	0.0652	1.42%	0.0146	3.02%	0.0311	0.03%	0.0003	1.84%	0.0189	0.95%	0.0098	0.04%	0.0004	0.00%	0.0000	0.01%	0.0001
Gas (Propane)	**0.8126**	**3.5590**	0.02%	0.0002	0.79%	0.0064	99.15%	0.8056	0.18%	0.0014	0.67%	0.0054	0.00%	0.0000	0.01%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Light Liquid	**2.0691**	**9.0628**	0.02%	0.0004	0.79%	0.0164	99.15%	2.0515	0.18%	0.0037	0.67%	0.0138	0.00%	0.0000	0.01%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**3.91**			**0.6775**		**0.2087**		**3.3946**		**0.1825**		**0.1411**		**0.0500**		**0.0654**		**0.0146**		**0.0311**		**0.0003**		**0.0189**		**0.0098**		**0.0004**		**0.0000**		**0.0001**
Total (T/yr):	**17.12**			**2.9676**		**0.9139**		**14.8682**		**0.7991**		**0.6178**		**0.2190**		**0.2864**		**0.0641**		**0.1360**		**0.0013**		**0.0827**		**0.0429**		**0.0018**		**0.0000**		**0.0006**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (1.0270 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.5375 lb/hr Propane

FUGITIVE AREA 5 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC (wt%)	Maximum CO_2 (wt%)	Maximum CH_4 (wt%)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual (T/yr)
Valves												
Gas Streams	1,605	0.0045	8,760	20%	1%	70%	96%	0.1274	0.5579	2.79E-02	1.95E+00	48.8474
Gas Stream (Propane)	34	0.0045	8,760	100%	0%	0%	96%	0.0135	0.0591	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	1,625	0.0025	8,760	100%	0%	0%	95%	0.4478	1.9614	0.00E+00	0.00E+00	0.0000
Relief Valves												
Gas Streams	52	0.0088	8,760	20%	1%	70%	0%	0.2018	0.8837	4.42E-02	3.09E+00	77.3713
Gas Stream (Propane)	9	0.0088	8,760	100%	0%	0%	0%	0.1746	0.7648	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	45	0.0075	8,760	100%	0%	0%	0%	0.7441	3.2590	0.00E+00	0.00E+00	0.0000
Compressor Seals												
Gas Streams	5	0.0088	8,760	20%	1%	70%	0%	0.0194	0.0850	4.25E-03	2.97E-01	7.4395
Gas Stream (Propane)	4	0.0088	8,760	100%	0%	0%	0%	0.0776	0.3399	0.00E+00	0.00E+00	0.0000
Pump Seals												
Light Liquid Stream	15	0.013	8,760	100%	0%	0%	88%	0.0516	0.2260	0.00E+00	0.00E+00	0.0000
Flanges												
Gas Streams	1,311	0.00039	8,760	20%	1%	70%	0%	0.2254	0.9874	4.94E-02	3.46E+00	86.4492
Gas Stream (Propane)	110	0.00039	8,760	100%	0%	0%	0%	0.0946	0.4143	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	846	0.00011	8,760	100%	0%	0%	0%	0.2052	0.8986	0.00E+00	0.00E+00	0.0000
Connectors												
Gas Streams	4,475	0.0002	8,760	20%	1%	70%	81%	0.0750	0.3284	1.64E-02	1.15E+00	28.7522
Gas Stream (Propane)	304	0.0002	8,760	100%	0%	0%	81%	0.0255	0.1115	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	6,976	0.00021	8,760	100%	0%	0%	81%	0.6136	2.6877	0.00E+00	0.00E+00	0.0000
							Gas Streams:	**0.6490**	**2.8425**	**0.1421**	**9.9487**	**248.8597**
							Gas Stream (Propane):	**0.3857**	**1.6896**	**0.0000**	**0.0000**	**0.0000**
							Light Liquid Stream:	**2.0623**	**9.0327**	**0.0000**	**0.0000**	**0.0000**
							TOTALS:	**3.10**	**13.56**	**0.14**	**9.95**	**248.86**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500 ppm.

[b] Hourly VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (20% VOC) * (100% - 96% reduction credit) = 0.1274 lb/hr

[c] Annual VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (8,760 hr/yr) * (20% VOC) * (100% - 96% reduction credit) / (2,000 lb/T) = 0.5579 T/yr

FUGITIVE AREA 5 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	PTE Total VOC		Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Toluene		Ethylbenzene		Xylene	
Stream	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly (lb/hr)**	**% in Stream**	**Hourly (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**
Gas (Natural Gas)	**0.6490**	**2.8425**	65.91%	0.4278	18.09%	0.1174	52.34%	0.3397	17.27%	0.1120	11.86%	0.0770	4.87%	0.0316	6.35%	0.0412	1.42%	0.0092	3.02%	0.0196	0.03%	0.0002	1.84%	0.0119	0.95%	0.0062	0.04%	0.0003	0.00%	0.0000	0.01%	0.0001
Gas (Propane)	**0.3857**	**1.6896**	0.02%	0.0001	0.79%	0.0031	99.15%	0.3825	0.18%	0.0007	0.67%	0.0026	0.00%	0.0000	0.01%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Light Liquid	**2.0623**	**9.0327**	0.02%	0.0004	0.79%	0.0164	99.15%	2.0446	0.18%	0.0037	0.67%	0.0138	0.00%	0.0000	0.01%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**3.10**			**0.4283**		**0.1368**		**2.7667**		**0.1164**		**0.0933**		**0.0316**		**0.0414**		**0.0093**		**0.0196**		**0.0002**		**0.0119**		**0.0062**		**0.0003**		**0.0000**		**0.0001**
Total (T/yr):	**13.56**			**1.8758**		**0.5993**		**12.1184**		**0.5099**		**0.4087**		**0.1384**		**0.1812**		**0.0406**		**0.0860**		**0.0008**		**0.0523**		**0.0271**		**0.0011**		**0.0000**		**0.0004**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.6490 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.3397 lb/hr Propane

FUGITIVE AREA 6 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC (wt%)	Maximum CO_2 (wt%)	Maximum CH_4 (wt%)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual (T/yr)
Valves												
Gas Streams	1,605	0.0045	8,760	20%	1%	70%	96%	0.1274	0.5579	2.79E-02	1.95E+00	48.8474
Gas Stream (Propane)	34	0.0045	8,760	100%	0%	0%	96%	0.0135	0.0591	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	1,625	0.0025	8,760	100%	0%	0%	95%	0.4478	1.9614	0.00E+00	0.00E+00	0.0000
Relief Valves												
Gas Streams	52	0.0088	8,760	20%	1%	70%	0%	0.2018	0.8837	4.42E-02	3.09E+00	77.3713
Gas Stream (Propane)	9	0.0088	8,760	100%	0%	0%	0%	0.1746	0.7648	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	45	0.0075	8,760	100%	0%	0%	0%	0.7441	3.2590	0.00E+00	0.00E+00	0.0000
Compressor Seals												
Gas Streams	5	0.0088	8,760	20%	1%	70%	0%	0.0194	0.0850	4.25E-03	2.97E-01	7.4395
Gas Stream (Propane)	4	0.0088	8,760	100%	0%	0%	0%	0.0776	0.3399	0.00E+00	0.00E+00	0.0000
Pump Seals												
Light Liquid Stream	15	0.013	8,760	100%	0%	0%	88%	0.0516	0.2260	0.00E+00	0.00E+00	0.0000
Flanges												
Gas Streams	1,311	0.00039	8,760	20%	1%	70%	0%	0.2254	0.9874	4.94E-02	3.46E+00	86.4492
Gas Stream (Propane)	110	0.00039	8,760	100%	0%	0%	0%	0.0946	0.4143	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	846	0.00011	8,760	100%	0%	0%	0%	0.2052	0.8986	0.00E+00	0.00E+00	0.0000
Connectors												
Gas Streams	4,475	0.0002	8,760	20%	1%	70%	81%	0.0750	0.3284	1.64E-02	1.15E+00	28.7522
Gas Stream (Propane)	304	0.0002	8,760	100%	0%	0%	81%	0.0255	0.1115	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	6,976	0.00021	8,760	100%	0%	0%	81%	0.6136	2.6877	0.00E+00	0.00E+00	0.0000
							Gas Streams:	**0.6490**	**2.8425**	**0.1421**	**9.9487**	**248.8597**
							Gas Stream (Propane):	**0.3857**	**1.6896**	**0.0000**	**0.0000**	**0.0000**
							Light Liquid Stream:	**2.0623**	**9.0327**	**0.0000**	**0.0000**	**0.0000**
							TOTALS:	**3.10**	**13.56**	**0.14**	**9.95**	**248.86**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500 ppm.

[b] Hourly VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (20% VOC) * (100% - 96% reduction credit) = 0.1274 lb/hr

[c] Annual VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (8,760 hr/yr) * (20% VOC) * (100% - 96% reduction credit) / (2,000 lb/T) = 0.5579 T/yr

FUGITIVE AREA 6 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	PTE Total VOC		Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Toluene		Ethylbenzene		Xylene	
Stream	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly (lb/hr)**	**% in Stream**	**Hourly (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**
Gas (Natural Gas)	**0.6490**	**2.8425**	65.91%	0.4278	18.09%	0.1174	52.34%	0.3397	17.27%	0.1120	11.86%	0.0770	4.87%	0.0316	6.35%	0.0412	1.42%	0.0092	3.02%	0.0196	0.03%	0.0002	1.84%	0.0119	0.95%	0.0062	0.04%	0.0003	0.00%	0.0000	0.01%	0.0001
Gas (Propane)	**0.3857**	**1.6896**	0.02%	0.0001	0.79%	0.0031	99.15%	0.3825	0.18%	0.0007	0.67%	0.0026	0.00%	0.0000	0.01%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Light Liquid	**2.0623**	**9.0327**	0.02%	0.0004	0.79%	0.0164	99.15%	2.0446	0.18%	0.0037	0.67%	0.0138	0.00%	0.0000	0.01%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**3.10**			**0.4283**		**0.1368**		**2.7667**		**0.1164**		**0.0933**		**0.0316**		**0.0414**		**0.0093**		**0.0196**		**0.0002**		**0.0119**		**0.0062**		**0.0003**		**0.0000**		**0.0001**
Total (T/yr):	**13.56**			**1.8758**		**0.5993**		**12.1184**		**0.5099**		**0.4087**		**0.1384**		**0.1812**		**0.0406**		**0.0860**		**0.0008**		**0.0523**		**0.0271**		**0.0011**		**0.0000**		**0.0004**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.6490 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.3397 lb/hr Propane

FUGITIVE AREA 7 POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Component	Number of Components	Emission Factors [a] (kg/hr-component)	Operating Hours (hr/yr)	Maximum VOC (wt%)	Maximum CO_2 (wt%)	Maximum CH_4 (wt%)	Reduction Credit [a] (%)	PTE VOC Hourly [b] (lb/hr)	PTE VOC Annual [c] (T/yr)	PTE CO_2 Annual [c] (T/yr)	PTE Methane Annual [c] (T/yr)	PTE CO_2e Annual (T/yr)
Valves												
Gas Streams	1,605	0.0045	8,760	20%	1%	70%	96%	0.1274	0.5579	2.79E-02	1.95E+00	48.8474
Gas Stream (Propane)	34	0.0045	8,760	100%	0%	0%	96%	0.0135	0.0591	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	1,625	0.0025	8,760	100%	0%	0%	95%	0.4478	1.9614	0.00E+00	0.00E+00	0.0000
Relief Valves												
Gas Streams	52	0.0088	8,760	20%	1%	70%	0%	0.2018	0.8837	4.42E-02	3.09E+00	77.3713
Gas Stream (Propane)	9	0.0088	8,760	100%	0%	0%	0%	0.1746	0.7648	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	45	0.0075	8,760	100%	0%	0%	0%	0.7441	3.2590	0.00E+00	0.00E+00	0.0000
Compressor Seals												
Gas Streams	5	0.0088	8,760	20%	1%	70%	0%	0.0194	0.0850	4.25E-03	2.97E-01	7.4395
Gas Stream (Propane)	4	0.0088	8,760	100%	0%	0%	0%	0.0776	0.3399	0.00E+00	0.00E+00	0.0000
Pump Seals												
Light Liquid Stream	15	0.013	8,760	100%	0%	0%	88%	0.0516	0.2260	0.00E+00	0.00E+00	0.0000
Flanges												
Gas Streams	1,311	0.00039	8,760	20%	1%	70%	0%	0.2254	0.9874	4.94E-02	3.46E+00	86.4492
Gas Stream (Propane)	110	0.00039	8,760	100%	0%	0%	0%	0.0946	0.4143	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	846	0.00011	8,760	100%	0%	0%	0%	0.2052	0.8986	0.00E+00	0.00E+00	0.0000
Connectors												
Gas Streams	4,475	0.0002	8,760	20%	1%	70%	81%	0.0750	0.3284	1.64E-02	1.15E+00	28.7522
Gas Stream (Propane)	304	0.0002	8,760	100%	0%	0%	81%	0.0255	0.1115	0.00E+00	0.00E+00	0.0000
Light Liquid Stream	6,976	0.00021	8,760	100%	0%	0%	81%	0.6136	2.6877	0.00E+00	0.00E+00	0.0000
							Gas Streams:	**0.6490**	**2.8425**	**0.1421**	**9.9487**	**248.8597**
							Gas Stream (Propane):	**0.3857**	**1.6896**	**0.0000**	**0.0000**	**0.0000**
							Light Liquid Stream:	**2.0623**	**9.0327**	**0.0000**	**0.0000**	**0.0000**
							TOTALS:	**3.10**	**13.56**	**0.14**	**9.95**	**248.86**

[a] Fugitive Emission Factors are per EPA document EPA-453/R-95-017; dated November 1995; pp.2-15. The emission factors are for total hydrocarbon. Reduction Credits are per EPA Leak Detection and Repair - A Best Practices Guide, Table 4.1 for refineries with a leak definition of 500 ppm.

[b] Hourly VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (20% VOC) * (100% - 96% reduction credit) = 0.1274 lb/hr

[c] Annual VOC emission rates are calculated as follows:
(1,605 components) * (0.0045 kg/hr-component) * (1 lb/0.454 kg) * (8,760 hr/yr) * (20% VOC) * (100% - 96% reduction credit) / (2,000 lb/T) = 0.5579 T/yr

FUGITIVE AREA 7 POTENTIAL TO EMIT (SPECIATED)

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	PTE Total VOC		Methane		Ethane		Propane		N-Butane		Isobutane		N-Pentane		Isopentane		n-Hexane		Other Hexanes		Benzene		Heptane		Octane+		Toluene		Ethylbenzene		Xylene	
Stream	**Hourly (lb/hr)**	**Annual (T/yr)**	**% in Stream**	**Hourly (lb/hr)**	**% in Stream**	**Hourly (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**	**% in VOC**	**Hourly[a] (lb/hr)**
Gas (Natural Gas)	**0.6490**	**2.8425**	65.91%	0.4278	18.09%	0.1174	52.34%	0.3397	17.27%	0.1120	11.86%	0.0770	4.87%	0.0316	6.35%	0.0412	1.42%	0.0092	3.02%	0.0196	0.03%	0.0002	1.84%	0.0119	0.95%	0.0062	0.04%	0.0003	0.00%	0.0000	0.01%	0.0001
Gas (Propane)	**0.3857**	**1.6896**	0.02%	0.0001	0.79%	0.0031	99.15%	0.3825	0.18%	0.0007	0.67%	0.0026	0.00%	0.0000	0.01%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Light Liquid	**2.0623**	**9.0327**	0.02%	0.0004	0.79%	0.0164	99.15%	2.0446	0.18%	0.0037	0.67%	0.0138	0.00%	0.0000	0.01%	0.0001	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Total (lb/hr):	**3.10**			**0.4283**		**0.1368**		**2.7667**		**0.1164**		**0.0933**		**0.0316**		**0.0414**		**0.0093**		**0.0196**		**0.0002**		**0.0119**		**0.0062**		**0.0003**		**0.0000**		**0.0001**
Total (T/yr):	**13.56**			**1.8758**		**0.5993**		**12.1184**		**0.5099**		**0.4087**		**0.1384**		**0.1812**		**0.0406**		**0.0860**		**0.0008**		**0.0523**		**0.0271**		**0.0011**		**0.0000**		**0.0004**

[a] An example calculation for propane follows:

Propane (lb/hr) = (PTE Total VOC, lb/hr) * (% Propane in VOC)

Propane (lb/hr) = (0.6490 lb/hr Total VOC) * (52.34% Propane in VOC)

Propane (lb/hr) = 0.3397 lb/hr Propane

GLYCOL DEHYDRATOR POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

	Control Device Efficiency
Flash Tank	98%
Condenser Vent	98%

	Emission Unit ID S006					
	Regenerator Emissions		Flash Tank Emissions		Total Emissions	
Component	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)
Carbon Dioxide	0.0400	0.1754	0.0462	0.2024	0.0862	0.3777
Nitrogen	0.0007	0.0032	0.0117	0.0511	0.0124	0.0543
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	0.0959	0.4199	1.3986	6.1261	1.4945	6.5459
Ethane	0.1865	0.8170	0.8608	3.7703	1.0473	4.5874
Propane	0.2307	1.0103	0.4223	1.8499	0.6530	2.8601
Isobutane	0.0776	0.3397	0.0974	0.4267	0.1750	0.7664
n-Butane	0.1645	0.7204	0.1573	0.6888	0.3217	1.4092
Isopentane	0.0550	0.2410	0.0474	0.2074	0.1024	0.4484
n-Pentane	0.0584	0.2557	0.0401	0.1757	0.0985	0.4314
Cyclopentane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Hexane	0.0279	0.1224	0.0111	0.0487	0.0391	0.1711
Cyclohexane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Other Hexanes	0.0435	0.1907	0.0229	0.1002	0.0664	0.2909
Heptanes	0.0636	0.2786	0.0131	0.0575	0.0767	0.3361
Methylcyclohexane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Benzene	0.0300	0.1315	0.0004	0.0017	0.0304	0.1332
Toluene	0.0520	0.2280	0.0004	0.0020	0.0525	0.2299
Ethylbenzene	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Xylenes	0.0288	0.1262	0.0001	0.0004	0.0289	0.1266
C8+ Heavies	0.1327	0.5813	0.0030	0.0131	0.1357	0.5944
2,2,4-trimethylpentane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.96	4.23	0.82	3.57	1.78	7.80

Notes:

1. A 10% safety factor has been added to all emissions to account for variability in gas composition. Although the still vent will employ a BTEX condenser, no control from the condenser has been taken into account for this PTE.

2. Dehydration unit S006 emissions from the BTEX condenser and flash tank are routed to the hot oil heater (unit ID S001) for combustion as fuel.

CALCULATION OF PRESSURIZED TRUCK UNLOADING POTENTIAL TO EMIT

AIR PERMIT CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emissions from Disconnecting Loading Lines from Pressurized Truck Unloading
Line Diameter 4 inches
Line Length 8 feet
Volume in Line 0.698 ft^3

A maximum of 22,000 bbl/day of condensate or NGL can be unloaded at the Plant. Assumed 200 barrels/truck for calculation of disconnects. Assumed that unloading operations are carried out only during daytime work shift.

Sample Calculations:

Hourly PTE = (Pressure, psia) * (Volume, ft^3) * (Molecular Weight, lb/lbmol) * (Number of Disconnects per Hour) * (% VOC) / ((Temperature, deg R) * (Gas Constant, ft^3*psia/lb-mol*deg R)) * (1-% Control, %)
Hourly PTE = (150.0 psia) * (0.698 cubic ft) * (46.25 lb/lbmol) * (9.2 disconnects/hr) * (0.85) / ((529.7 deg R) * (10.73 cubic ft*psia/lb-mol*deg R)) * (1-0.00) = 6.64 lb/hr

Annual PTE = (Pressure, psia) * (Volume, ft^3) * (Molecular Weight, lb/lb-mol) * (Number of Disconnects per Year) * (% VOC) / ((Temperature, deg R) * (Gas Constant, ft^3*psia/lb-mol*deg R) * (2,000 lbs/T)) * (1-% Control, %)
Annual PTE = (150.0 psia) * (0.698 cubic ft) * (46.25 lb/lbmol) * (40,150 disconnects/yr) * (0.85) / ((529.7 deg R) * (10.73 cubic ft*psia/lb-mol*deg R) * (2,000 lbs/T)) * (1-0.00) = 14.54 T/yr

Emission Unit ID	Emission Unit Description	Emission Point ID	Hourly Number of Disconnects (disconnects/hr)	Annual Number of Disconnects (disconnects/yr)	Vapor Pressure (psia)	Molecular Weight (lb/lb-mole)	Temp. (deg R)	Gas Constant (ft^3*psia/ lb-mol*deg R)	Volume (ft^3)	% VOC	% Methane	% Carbon Dioxide	% Control	Hourly PTE VOC (lb/hr)	Annual PTE VOC (T/yr)	Annual PTE Methane (T/yr)	Annual PTE Carbon Dioxide (T/yr)
S055	Pressurized Condensate/NGL Unloading	P055	9	40,150	150.0	46.25	529.7	10.73	0.698	85%	1.00%	1.00%	0%	6.64	14.54	0.17	0.17

1. Emission calculations are for unloading of condensate and NGL into slug catchers at the inlet of the Plant. Condensate representation has been selected tobe conservative.
2. VOC, methane, and carbon dioxide percentages taken from stream composition for condensate gas.
3. VOC emission speciation based on condensate gas compositions. Emission speciation is as shown below.

	Condensate	
Component	**Hourly (lb/hr)**	**Annual (T/yr)**
Benzene	0.00	0.00
Toluene	0.00	0.00
Ethylbenzene	0.00	0.00
Xylene	0.00	0.00
n-Hexane	0.34	0.75

CALCULATION OF PRESSURIZED TRUCK LOADING POTENTIAL TO EMIT

CLASS II ADMINISTRATIVE UPDATE

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emissions from Disconnecting Loading Lines from Pressurized Truck Loading
Line Diameter 4 inches
Line Length 8 feet
Volume in Line 0.698 ft^3

Sample Calculations:

Hourly PTE = (Pressure, psia) * (Volume, ft^3) * (Molecular Weight, lb/lbmol) * (Number of Disconnects per Hour) * (% VOC) / ((Temperature, deg R) * (Gas Constant, ft^3*psia/lb-mol*deg R)) * (1-% Control, %)
Hourly PTE = (150.0 psia) * (0.698 cubic ft) * (44.01 lb/lbmol) * (3.0 disconnects/hr) * (1.00) / ((529.7 deg R) * (10.73 cubic ft*psia/lb-mol*deg R)) * (1-0.00) = 2.43 lb/hr

Annual PTE = (Pressure, psia) * (Volume, ft^3) * (Molecular Weight, lb/lb-mol) * (Number of Disconnects per Year) * (% VOC) / ((Temperature, deg R) * (Gas Constant, ft^3*psia/lb-mol*deg R) * (2,000 lbs/T)) * (1-% Control, %)
Annual PTE = (150.0 psia) * (0.698 cubic ft) * (44.01 lb/lbmol) * (9,000 disconnects/yr) * (1.00) / ((529.7 deg R) * (10.73 cubic ft*psia/lb-mol*deg R) * (2,000 lbs/T)) * (1-0.00) = 3.65 T/yr

Emission Unit ID	Emission Unit Description	Emission Point ID	Hourly Number of Disconnects (disconnects/hr)	Annual Number of Disconnects (disconnects/yr)	Vapor Pressure (psia)	Molecular Weight (lb/lb-mole)	Temp. (deg R)	Gas Constant (ft^3*psia/ lb-mol*deg R)	Volume (ft^3)	% VOC	% Methane	% Carbon Dioxide	% Control	Hourly PTE VOC (lb/hr)	Annual PTE VOC (T/yr)	Annual PTE Methane (T/yr)	Annual PTE Carbon Dioxide (T/yr)
S008	Pressurized Propane Loading	P008	3	9,000	150.0	44.01	529.7	10.73	0.698	100%	0.00%	0.00%	0%	2.43	3.65	0.00	0.00
S008	Pressurized i-Butane Loading	P008	1	314	150.0	57.79	529.7	10.73	0.698	100%	0.00%	0.00%	0%	1.06	0.17	0.00	0.00
S008	Pressurized Butanes Loading	P008	1	314	150.0	58.21	529.7	10.73	0.698	100%	0.00%	0.00%	0%	1.07	0.17	0.00	0.00
S008	Pressurized Natural Gasoline Loading	P008	1	314	150.0	76.82	529.7	10.73	0.698	100%	0.00%	0.00%	0%	1.42	0.22	0.00	0.00
													Total:	5.99	4.21	0.00	0.00

1. Emission calculations are for truck loading of propane, butane, and natural gasoline products for offsite transportation.
2. VOC, methane, and carbon dioxide percentages taken from stream composition for each product.
3. VOC emission speciation based on product compositions. Emission speciation is as shown below.

	Propane		i-Butane		Butane		Natural Gasoline		Total	
Component	**Hourly (lb/hr)**	**Annual (T/yr)**	**Hourly (lb/hr)**	**Annual (T/yr)**	**Hourly (lb/hr)**	**Annual (T/yr)**	**Hourly (lb/hr)**	**Annual (T/yr)**	**Hourly (lb/hr)**	**Annual (T/yr)**
Benzene	--	--	--	--	--	--	0.01	0.00	0.01	0.00
Toluene	--	--	--	--	--	--	0.01	0.00	0.01	0.00
Ethylbenzene	--	--	--	--	--	--	0.001	0.0001	0.001	0.0001
Xylene	--	--	--	--	--	--	0.004	0.001	0.004	0.001
n-Hexane	--	--	--	--	--	--	0.07	0.01	0.07	0.01

BARGE LOADING POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Sample Calculations for Emission Unit ID S033 (Natural Gasoline):

Hourly Emissions = (Max. Hourly Throughput, Mgal/hr) * (Max. Loading Loss, lb/Mgal) * (VOC Fraction)
Hourly Emissions = (240.00 Mgal/hr) * (0.41 lb/Mgal) * (1.00) = 97.22 lb/hr

Annual Emissions = (Max. Annual Throughput, Mgal/yr) * (Max. Loading Loss, lb/Mgal) * (VOC Fraction) / (2,000 lb/T)
Annual Emissions = (156,240.00 Mgal/yr) * (0.41 lb/Mgal) * (1.00) / (2,000 lb/T) = 31.65 T/yr

Emission Unit ID	Emission Unit Description	Emission Point ID	Emission Point Description	VOC Fraction	Hourly Throughput (Mgal/hr)	Barge Capacity (bbl)	Number of Loading Events per Month	Annual Throughput (Mgal/yr)	Loading Loss (lb/Mgal)	Hourly Emissions (lb/hr)	Annual Emissions (T/yr)
S033	Barge Loading Vent	P033	Barge Loading Vent	1.00	240.00	10,000.00	31	156,240.00	0.41	97.22	31.65
S033	Barge Loading Vent	P033	Barge Loading Vent	1.00	240.00	25,000.00	20	252,000.00	0.41	97.22	51.04
									Total:	97.22	82.69

1. Loading Loss (lb/Mgal) determined as the maximum VOC emissions measured during several loading events.
2. Hourly throughput based on pump capacity of 4,000 gal/min.
3. Barge capacity of 10,000 bbl based on the current maximum barge size. Barge capacity of 25,000 bbl is based on proposed project expectations.
4. HAP emissions estimated based on weight percentages from Safety Data Sheet as shown:
5. Annual throughput based on current production volumes, adjusted for anticipated production volumes.

Component	Weight %	Hourly (lb/hr)	Annual (T/yr)
Benzene	0.45%	0.44	0.37
Toluene	0.75%	0.73	0.62
Xylene	0.29%	0.28	0.24

GASOLINE DISPENSER POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Sample Calculations for Emission Unit ID L-1 (Gasoline):

Hourly Emissions = (Max. Hourly Throughput, Mgal/hr) * (Max. Loading Loss, lb/Mgal) * (VOC Fraction)
Hourly Emissions = (0.02 Mgal/hr) * (12.00 lb/Mgal) * (1.00) = 0.18 lb/hr

Annual Emissions = (Max. Annual Throughput, Mgal/yr) * (Max. Loading Loss, lb/Mgal) * (VOC Fraction) / (2,000 lb/T)
Annual Emissions = (11.88 Mgal/yr) * (12.00 lb/Mgal) * (1.00) / (2,000 lb/T) = 0.07128 T/yr

Emission Unit ID	Emission Unit Description	Emission Point ID	Emission Point Description	VOC Fraction	Hourly Throughput (Mgal/hr)	Number of Loading Events per Month	Annual Throughput (Mgal/yr)	Loading Loss (lb/Mgal)	Hourly Emissions (lb/hr)	Annual Emissions (T/yr)
L-1	Gasoline Dispenser Loading	L-1	Gasoline Dispenser Loading	1.00	0.02	66	12	12.00	0.18	0.071

1. Loading Loss (lb/Mgal) is from AP-42, Table 5.2-5, dated June 2008. The Loading Loss used is for gasoline splash loading - dedicated normal service.
2. HAP emissions are expected to be negligible.

TRUCK LOADING POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Sample Calculations:

Maximum Loading Loss = 12.46 * (Saturation Factor) * (Max. Vapor Pressure, psia) * (Vapor MW, lb/lbmol) / (Max. Temp., R)
Maximum Loading Loss = 12.46 * (0.60) * (0.30 psia) * (60.00 lb/lbmole) / (61.50 + 460) R = 0.2580 lb/Mgal

Average Loading Loss = 12.46 * (Saturation Factor) * (Avg. True Vapor Pressure, psia) * (Vapor MW, lb/lbmol) / (Avg. Temp., R)
Average Loading Loss = 12.46 * (0.60) * (0.12 psia) * (60.00 lb/lbmole) / (58.43 + 460) R = 0.1073 lb/Mgal

Hourly PTE = (Hourly Throughput, Mgal/hr) * (Max. Loading Loss, lb/Mgal)
Hourly PTE = (9.00 Mgal/hr) * (0.2580 lb/Mgal) = 2.32 lb/hr

Annual PTE = (Annual Throughput, Mgal/yr) * (Avg. Loading Loss, lb/Mgal) / (2,000 lb/T)
Annual PTE = (2,007.07 Mgal/yr) * (0.1073 lb/Mgal) / (2,000 lb/T) = 0.11 T/yr

Emission Unit ID	Emission Point ID	Emission Unit Description	Saturation Factor	Max. Vapor Pressure (psia)	Avg. Vapor Pressure (psia)	Vapor Molecular Weight (lb/lbmol)	Max. Temp. (F)	Avg. Temp. (F)	Hourly Throughput (Mgal/hr)	Annual Throughput (Mgal/yr)	VOC Fraction	Max. Loading Loss (lb/Mgal)	Avg. Loading Loss (lb/Mgal)	Control Efficiency	VOC Hourly PTE (lb/hr)	VOC Annual PTE (T/yr)
S015	P015	Slop Water Truck Loading	0.60	0.30	0.12	60.00	61.50	58.43	9.00	2,007.07	1.00	0.2580	0.1073	0%	2.32	0.11

1. Calculation method and factors per AP-42, Section 5.2, dated June 2008.
2. True Vapor Pressure, Molecular Weight, and Temperature taken from storage tank calculations.
3. Methane, carbon dioxide, and HAP emissions are expected to be negligible.

STORAGE TANKS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Variable	Description	Units	Value
L_T	Total Loss = Ls + Lw	Ton/yr	See Table
L_S	Standing Loss = 365 Vv Wv Ke Ks	lb/yr	See Table
L_W	Working Loss = 0.001 Mv Pv Q Kn Kp	lb/yr	See Table
L_H	Hourly Working Loss = 0.001 Mv Pmax Qh	lb/hr	See Table
	Roof Construction		Dome
DPb	Breather Vent Pressure Range	psi	0.06
I	Solar Insolation Factor	Btu/ft^2-day	1,123
P_A	Atmospheric Pressure	psia	14.7
T	Annual Average Temperature	°F	51.7
T_{AX}	Daily Maximum Ambient Temperature	°R	521.5
T_{AN}	Daily Minimum Ambient Temperature	°R	501.8
DT_A	Daily Average Ambient Temperature Range	°R	19.7
Kp	Product Factor		1

62.410292 23.0438 69.131401

69.131401 23.0438

			Tank Specifications							Material Specifications														VOC	
			V/H	D	H/L	Capacity	Color		a	Mv	P_{MAX}	Q'		DTv	Hvo	Vv	T_{LA}	P_{VA}	Wv	DPv	Ke	Ks	Kn	L_S	L_W	L_H	L_T
Description	Emission Unit ID	Material	Tank Type	Tank Diameter (ft)	Tank Height/ Length (ft)	Tank Capacity (bbl)	Paint Color	Paint Conditions	Paint Solar Absorbance Factor	Vapor Molecular Weight (lb/lbmol)	Reid Vapor Pressure (psi)	Max. Hourly Throughput (bbl/hr)	Annual Throughput (bbl)	Daily Vapor Temp. Range °F	Vapor Space Outage (ft)	Vapor Space Volume (ft^3)	Daily Average Liquid Surface Temp (°R)	Average Vapor Pressure (psia)	Vapor Density (lb/ft^3)	Daily Vapor Pressure Range	Vapor Space Expan. Factor	Vented Vapor Sat. Factor	Turnover Factor	Standing Loss per Tank (lb/yr)	Working Loss per Tank (lb/yr)	Total Loss (lb/hr)	Total Loss (T/yr)
1,000 gal Gasoline Dispensing Storage Tank	TK-L-1	Gasoline	H	5.42	6.00	23.81	White	Good	0.17	66.00	10.00	23.81	285.71	19.53	2.71	69.13	513.17	6.20	0.07	1.03	0.15	0.53	1.00	135.83	116.91	**15.71**	**0.13**
Slop Oil Storage Tank	TK-906	Water	V	15.50	16.00	493.48	Aluminum	Good	0.60	60.00	0.30	493.48	5,921.71	33.05	9.06	1,709.88	518.43	0.12	0.001	0.07	0.06	0.94	1.00	50.57	44.06	**8.88**	**0.05**
Produced Water Storage Tank	TK-907	Water	V	21.50	24.00	1,497.67	Aluminum	Good	0.60	60.00	0.30	1,497.67	17,972.00	33.05	13.47	4,891.29	518.43	0.12	0.001	0.07	0.06	0.92	1.00	140.81	133.71	**26.96**	**0.14**
Slop Oil Storage Tank	TK-2906	Water	V	15.50	16.00	493.48	Aluminum	Good	0.60	60.00	0.30	493.48	5,921.71	33.05	9.06	1,709.88	518.43	0.12	0.001	0.07	0.06	0.94	1.00	50.57	44.06	**8.88**	**0.05**
Produced Water Storage Tank	TK-2907	Water	V	21.50	24.00	1,497.67	Aluminum	Good	0.60	60.00	0.30	1,497.67	17,972.00	33.05	13.47	4,891.29	518.43	0.12	0.001	0.07	0.06	0.92	1.00	140.81	133.71	**26.96**	**0.14**
Glycol Sump	UT-607	Water	H	4.50	11.79	33.40	--	--	--	62.10	0.12	4.76	400.80	--	--	--	--	0.12	--	--	--	--	1.00	0.00	2.99	**0.04**	**0.001**
Glycol Sump	UT-608	Water	H	4.50	11.79	33.40	--	--	--	62.10	0.12	4.76	400.80	--	--	--	--	0.12	--	--	--	--	1.00	0.00	2.99	**0.04**	**0.001**

NOTE: Tank working and breathing emissions are based on the equations found in EPA AP-42 Chapter 7. All factors used are represented in the table on this page. Gasoline properties are taken from AP-42 Table 7.1-2 for RVP 10 gasoline.

Slop oil and produced water tank contents assume liquids are 98% water and 2% RVP 15 gasoline.

Glycol sumps are located underground, thus no standing losses are generated.

UNPAVED ROADS POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID **ROADS**

Input Parameters

Input	Symbol	Value	Units
Total Daily Delivery and Haulout Trips[a]	n	165	trips/day
Total Daily Commercial Vehicle Trips[b]	n	20	trips/day
Road-to-Plant Distance (one way)	d	1,000	ft
Delivery Days	D	365	days/yr
Days with Precipitation > 0.01"	P	150	days/yr
Empty Truck Weight	W_e	10	ton
Full Truck Weight	W_f	20	ton
Average Truck Weight	W	15	ton
Average Commercial Vehicle Weight	W	2	ton
Surface Material Silt Content	s	6.0	%

[a] Includes NGL deliveries, product, slop oil, produced water, and used oil loadouts.

[b] Includes Pickup trucks, and other vehicles that access the facility.

Calculation of Emission Factor, E (lb/VMT)

		k (unitless)	s (%)	W (tons)	a (unitless)	b (unitless)	E (lb/VMT)
Average NGL Truck	PM	4.9	6.0	15	0.7	0.45	6.22
Average NGL Truck	PM_{10}	1.5	6.0	15	0.9	0.45	1.66
Average NGL Truck	$PM_{2.5}$	0.15	6.0	15	0.9	0.45	0.17
Average Commercial Vehicle	PM	4.9	6.0	2	0.7	0.45	2.51
Average Commercial Vehicle	PM_{10}	1.5	6.0	2	0.9	0.45	0.67
Average Commercial Vehicle	$PM_{2.5}$	0.15	6.0	2	0.9	0.45	0.07

$E = k(s/12)^a(W/3)^b$ AP-42 Chapter 13.2.2, Eq. 1a, November 2006

Calculation of Emissions (T/yr)

		E (lb/VMT)	E_{ext} (lb/VMT)	VMT (miles/yr)	Emissions (T/yr)
Average NGL Truck	PM	6.22	3.67	22,813	41.81
Average NGL Truck	PM_{10}	1.66	0.98	22,813	11.14
Average NGL Truck	$PM_{2.5}$	0.17	0.10	22,813	1.11
Average Commercial Vehicle	PM	2.51	1.48	2,765	2.05
Average Commercial Vehicle	PM_{10}	0.67	0.39	2,765	0.55
Average Commercial Vehicle	$PM_{2.5}$	0.07	0.04	2,765	0.05
Total Emissions	PM	--	--	--	43.86
Total Emissions	PM_{10}	--	--	--	11.69
Total Emissions	$PM_{2.5}$	--	--	--	1.17

$E_{ext} = E[(365 - P)/365]$ AP-42 Chapter 13.2.2, Eq. 2, November 2006

AMINE PLANT VENT POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID	**S011**	**S054**

Still Vent:

	Emission Rates		**Emission Rates**	
	Hourly (lb/hr)	**Annual (T/yr)**	**Hourly (lb/hr)**	**Annual (T/yr)**
Methane	0.02	0.10	0.02	0.10
Propane	0.16	0.68	0.16	0.68
Methanol	1.82	7.99	1.82	7.99
CO_2	2,789.95	12,220.00	2,789.95	12,220.00
Total VOC	1.98	8.67	1.98	8.67
Control Efficiency (%)	--	--	100%	100%
Control Downtime (%)	--	--	5%	5%
Methane	--	--	0.02	0.005
Propane	--	--	0.16	0.03
Methanol	--	--	1.82	0.40
CO_2	--	--	2,789.95	611.00
Total VOC	--	--	1.98	0.43

Flash Tank (to Flare):

Gas Flow:	525.7792	scf/hr	525.7792	scf/hr
Heating Value:	1,761.18	Btu/scf	1,761.18	Btu/scf
Feed Rate:	0.9260	MMBtu/hr	0.9260	MMBtu/hr
Operating Hours:	8,760	hr/yr	8,760	hr/yr
VOC emissions:	0.4815	lb/hr	0.4815	lb/hr
HAP emissions:	0.0019	lb/hr	0.0019	lb/hr

Amine unit vent emissions taken from Promax simulation reports.

Values are full plant operation, with an inlet treating capacity of 81,523 bbl/day (equivalent to 129 MMscfd) per unit.

The amine unit at the Plant consists of two contactors with a single amine regenerator. The rich amine from both contactors is routed to the amine regenerator to remove CO_2 from the amine solution prior to being reused in the process.

Still vent emissions from unit S011 are vented to atmosphere. Still vent emissions from unit ID S054 are captured by a vapor recovery unit (VRU) and routed to the residue gas discharge line. During VRU downtime, emissions from the amine unit will vent to atmosphere. VRU downtime is not expected to exceed 5% of the total annual runtime.

Flash tank emissions are routed to the ground flare for combustion.

FIRE PUMP #1 POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID **S002**

Item	Value	Units
Rated Horsepower	700	Hp
Max. Fuel Consumption Rate	35.9	gal/hr
Max. Fuel Consumption Rate	4.92	MMBtu/hr
Annual Operating Hours	100	hr/yr
Annual Fuel Consumption	3,590	gal/yr
Sulfur Content of Fuel	0.0015	%
Heat Content of Fuel	137,030	Btu/gal

Pollutant	CAS	REF	Emission Factor	Units	Potential Emissions lb/hr	Potential Emissions T/yr
Criteria Pollutants						
NO_X	N/A	1	3	g/hp-hr	4.63	0.23
CO	630-08-0	1	2.6	g/hp-hr	4.01	0.20
VOC	N/A	1	3	g/hp-hr	4.63	0.23
PM_{10}	N/A	1	0.15	g/hp-hr	0.23	0.01
$PM_{2.5}$	N/A	1	0.15	g/hp-hr	0.23	0.01
SO_2	7446-09-5	2	1.52E-03	lb/MMBtu	0.01	0.0004
Hazardous Air Pollutants						
Acetaldehyde	75-07-0	3	2.52E-05	lb/MMBtu	1.2E-04	6.2E-06
Acrolein	107-02-8	3	7.88E-06	lb/MMBtu	3.9E-05	1.9E-06
Benzene	71-43-2	3	7.76E-04	lb/MMBtu	3.8E-03	1.9E-04
Formaldehyde	50-00-0	3	7.89E-05	lb/MMBtu	3.9E-04	1.9E-05
Toluene	108-88-3	3	2.81E-04	lb/MMBtu	1.4E-03	6.9E-05
Xylenes	1330-20-7	3	1.93E-04	lb/MMBtu	9.5E-04	4.7E-05
PAHs						
Acenaphthene	83-32-9	4	4.68E-06	lb/MMBtu	2.3E-05	1.2E-06
Acenaphthylene	208-96-8	4	9.23E-06	lb/MMBtu	4.5E-05	2.3E-06
Anthracene	120-12-7	4	1.23E-06	lb/MMBtu	6.1E-06	3.0E-07
Benzo(a)anthracene	56-55-3	4	6.22E-07	lb/MMBtu	3.1E-06	1.5E-07
Benzo(a)pyrene	50-32-8	4	2.57E-07	lb/MMBtu	1.3E-06	6.3E-08
Benzo(b)fluoranthene	205-99-2	4	1.11E-06	lb/MMBtu	5.5E-06	2.7E-07
Benzo(g,h,l)perylene	191-24-2	4	5.56E-07	lb/MMBtu	2.7E-06	1.4E-07
Benzo(k)fluoranthene	205-82-3	4	2.18E-07	lb/MMBtu	1.1E-06	5.4E-08
Chrysene	218-01-9	4	1.53E-06	lb/MMBtu	7.5E-06	3.8E-07
Dibenz(a,h)anthracene	53-70-3	4	3.46E-07	lb/MMBtu	1.7E-06	8.5E-08
Fluoranthene	206-44-0	4	4.03E-06	lb/MMBtu	2.0E-05	9.9E-07
Fluorene	86-73-7	4	1.28E-05	lb/MMBtu	6.3E-05	3.1E-06
Ideno(1,2,3-cd)pyrene	193-39-5	4	4.14E-07	lb/MMBtu	2.0E-06	1.0E-07
Naphthalene	91-20-3	4	1.30E-04	lb/MMBtu	6.4E-04	3.2E-05
Phenanthrene	85-01-8	4	4.08E-05	lb/MMBtu	2.0E-04	1.0E-05
Pyrene	129-00-0	4	3.71E-06	lb/MMBtu	1.8E-05	9.1E-07
Total PAH	---	4	2.12E-04	lb/MMBtu	1.0E-03	5.2E-05
Greenhouse Gases						
Carbon dioxide	124-38-9	2	165	lb/MMBtu	811.70	40.58
Methane	74-82-8	2	0.0081	lb/MMBtu	0.04	0.002
Nitrous oxide	10024-97-2	---	0	lb/MMBtu	0.00	0.00
CO_2e	N/A	5	---	---	812.69	40.63

Total Criteria :	**0.69**	**T/yr**
Total HAPs:	**0.0004**	**T/yr**

Notes: 1. 40 CFR 60 Subpart IIII, Table 4
2. AP-42 Table 3.4-1 (10/96)
3. AP-42 Table 3.4-3 (10/96)
4. AP-42 Table 3.4-4 (10/96)
5. 40 CFR 98 Table A-1

FIRE PUMP #2 POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID **S003**

Item	Value	Units
Rated Horsepower	700	Hp
Max. Fuel Consumption Rate	35.9	gal/hr
Max. Fuel Consumption Rate	4.92	MMBtu/hr
Annual Operating Hours	100	hr/yr
Annual Fuel Consumption	3,590	gal/yr
Sulfur Content of Fuel	0.0015	%
Heat Content of Fuel	137,030	Btu/gal

Pollutant	CAS	REF	Emission Factor	Units	Potential Emissions lb/hr	Potential Emissions T/yr
Criteria Pollutants						
NO_X	N/A	1	3	g/hp-hr	4.63	0.23
CO	630-08-0	1	2.6	g/hp-hr	4.01	0.20
VOC	N/A	1	3	g/hp-hr	4.63	0.23
PM_{10}	N/A	1	0.15	g/hp-hr	0.23	0.01
$PM_{2.5}$	N/A	1	0.15	g/hp-hr	0.23	0.01
SO_2	7446-09-5	2	1.52E-03	lb/MMBtu	0.01	0.0004
Hazardous Air Pollutants						
Acetaldehyde	75-07-0	3	2.52E-05	lb/MMBtu	1.2E-04	6.2E-06
Acrolein	107-02-8	3	7.88E-06	lb/MMBtu	3.9E-05	1.9E-06
Benzene	71-43-2	3	7.76E-04	lb/MMBtu	3.8E-03	1.9E-04
Formaldehyde	50-00-0	3	7.89E-05	lb/MMBtu	3.9E-04	1.9E-05
Toluene	108-88-3	3	2.81E-04	lb/MMBtu	1.4E-03	6.9E-05
Xylenes	1330-20-7	3	1.93E-04	lb/MMBtu	9.5E-04	4.7E-05
PAHs						
Acenaphthylene	208-96-8	4	9.23E-06	lb/MMBtu	4.5E-05	2.3E-06
Acenaphthene	83-32-9	4	4.68E-06	lb/MMBtu	2.3E-05	1.2E-06
Anthracene	120-12-7	4	1.23E-06	lb/MMBtu	6.1E-06	3.0E-07
Benzo(a)anthracene	56-55-3	4	6.22E-07	lb/MMBtu	3.1E-06	1.5E-07
Benzo(a)pyrene	50-32-8	4	2.57E-07	lb/MMBtu	1.3E-06	6.3E-08
Benzo(b)fluoranthene	205-99-2	4	1.11E-06	lb/MMBtu	5.5E-06	2.7E-07
Benzo(g,h,l)perylene	191-24-2	4	5.56E-07	lb/MMBtu	2.7E-06	1.4E-07
Benzo(k)fluoranthene	205-82-3	4	2.18E-07	lb/MMBtu	1.1E-06	5.4E-08
Chrysene	218-01-9	4	1.53E-06	lb/MMBtu	7.5E-06	3.8E-07
Dibenz(a,h)anthracene	53-70-3	4	3.46E-07	lb/MMBtu	1.7E-06	8.5E-08
Fluoranthene	206-44-0	4	4.03E-06	lb/MMBtu	2.0E-05	9.9E-07
Fluorene	86-73-7	4	1.28E-05	lb/MMBtu	6.3E-05	3.1E-06
Ideno(1,2,3-cd)pyrene	193-39-5	4	4.14E-07	lb/MMBtu	2.0E-06	1.0E-07
Naphthalene	91-20-3	4	1.30E-04	lb/MMBtu	6.4E-04	3.2E-05
Phenanthrene	85-01-8	4	4.08E-05	lb/MMBtu	2.0E-04	1.0E-05
Pyrene	129-00-0	4	3.71E-06	lb/MMBtu	1.8E-05	9.1E-07
Total PAH	---	4	2.12E-04	lb/MMBtu	1.0E-03	5.2E-05
Greenhouse Gases						
Carbon dioxide	124-38-9	2	165	lb/MMBtu	811.70	40.58
Methane	74-82-8	2	0.0081	lb/MMBtu	0.04	0.00
Nitrous oxide	10024-97-2	---	0	lb/MMBtu	0.00	0.00
CO_2e	N/A	5	---	---	812.69	40.63

Total Criteria :	**0.69**	**T/yr**
Total HAPs:	**0.0004**	**T/yr**

Notes: 1. 40 CFR 60 Subpart IIII, Table 4
2. AP-42 Table 3.4-1 (10/96)
3. AP-42 Table 3.4-3 (10/96)
4. AP-42 Table 3.4-4 (10/96)
5. 40 CFR 98 Table A-1

DIESEL ENGINE POTENTIAL TO EMIT

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Emission Unit ID **S058**

This emission unit consists of one or multiple engines with a total horsepower not to exceed 3,000 hp.

The engines will be diesel-fueled, and may consist of fire-pump engines, or generator engines to power electric-driven fire pumps.

Item	Value	Units
Rated Horsepower	3,000	Hp
Rated Kilowatts	2,237	kW
Max. Fuel Consumption Rate	153.9	gal/hr
Max. Fuel Consumption Rate	21.08	MMBtu/hr
Annual Operating Hours	100	hr/yr
Annual Fuel Consumption	15,386	gal/yr
Sulfur Content of Fuel	0.0015	%
Heat Content of Fuel	137,030	Btu/gal

Pollutant	CAS	REF	Emission Factor	Units	Potential Emissions lb/hr	Potential Emissions T/yr
Criteria Pollutants (Fire Pump Engines)						
NO_X	N/A	1	4.8	g/hp-hr	31.75	1.59
CO	630-08-0	1	2.6	g/hp-hr	17.20	0.86
VOC	N/A	1	4.8	g/hp-hr	31.75	1.59
PM_{10}	N/A	1	0.15	g/hp-hr	0.99	0.05
$PM_{2.5}$	N/A	1	0.15	g/hp-hr	0.99	0.05
SO_2	7446-09-5	2	1.52E-03	lb/MMBtu	0.03	0.002
Criteria Pollutants (Generator Engines)						
NO_X	N/A	6	6.4	g/kW-hr	31.56	1.58
CO	630-08-0	6	3.5	g/kW-hr	17.26	0.86
VOC	N/A	6	6.4	g/kW-hr	31.56	1.58
PM_{10}	N/A	6	0.2	g/kW-hr	0.99	0.05
$PM_{2.5}$	N/A	6	0.2	g/kW-hr	0.99	0.05
SO_2	7446-09-5	2	1.52E-03	lb/MMBtu	0.03	0.002
Criteria Pollutants (Worst Case, see note 7)						
NO_X	N/A	7			31.75	1.59
CO	630-08-0	7			17.26	0.86
VOC	N/A	7			31.75	1.59
PM_{10}	N/A	7			0.99	0.05
$PM_{2.5}$	N/A	7			0.99	0.05
SO_2	7446-09-5	7			0.03	0.002
Hazardous Air Pollutants						
Acetaldehyde	75-07-0	3	2.52E-05	lb/MMBtu	5.3E-04	2.7E-05
Acrolein	107-02-8	3	7.88E-06	lb/MMBtu	1.7E-04	8.3E-06
Benzene	71-43-2	3	7.76E-04	lb/MMBtu	1.6E-02	8.2E-04
Formaldehyde	50-00-0	3	7.89E-05	lb/MMBtu	1.7E-03	8.3E-05
Toluene	108-88-3	3	2.81E-04	lb/MMBtu	5.9E-03	3.0E-04
Xylenes	1330-20-7	3	1.93E-04	lb/MMBtu	4.1E-03	2.0E-04
PAHs						
Acenaphthylene	208-96-8	4	9.23E-06	lb/MMBtu	1.9E-04	9.7E-06
Acenaphthene	83-32-9	4	4.68E-06	lb/MMBtu	9.9E-05	4.9E-06
Anthracene	120-12-7	4	1.23E-06	lb/MMBtu	2.6E-05	1.3E-06
Benzo(a)anthracene	56-55-3	4	6.22E-07	lb/MMBtu	1.3E-05	6.6E-07
Benzo(a)pyrene	50-32-8	4	2.57E-07	lb/MMBtu	5.4E-06	2.7E-07
Benzo(b)fluoranthene	205-99-2	4	1.11E-06	lb/MMBtu	2.3E-05	1.2E-06
Benzo(g,h,l)perylene	191-24-2	4	5.56E-07	lb/MMBtu	1.2E-05	5.9E-07
Benzo(k)fluoranthene	205-82-3	4	2.18E-07	lb/MMBtu	4.6E-06	2.3E-07
Chrysene	218-01-9	4	1.53E-06	lb/MMBtu	3.2E-05	1.6E-06
Dibenz(a,h)anthracene	53-70-3	4	3.46E-07	lb/MMBtu	7.3E-06	3.6E-07
Fluoranthene	206-44-0	4	4.03E-06	lb/MMBtu	8.5E-05	4.2E-06
Fluorene	86-73-7	4	1.28E-05	lb/MMBtu	2.7E-04	1.3E-05
Ideno(1,2,3-cd)pyrene	193-39-5	4	4.14E-07	lb/MMBtu	8.7E-06	4.4E-07
Naphthalene	91-20-3	4	1.30E-04	lb/MMBtu	2.7E-03	1.4E-04
Phenanthrene	85-01-8	4	4.08E-05	lb/MMBtu	8.6E-04	4.3E-05
Pyrene	129-00-0	4	3.71E-06	lb/MMBtu	7.8E-05	3.9E-06
Total PAH	---	4	2.12E-04	lb/MMBtu	4.5E-03	2.2E-04
Greenhouse Gases						
Carbon dioxide	124-38-9	2	165	lb/MMBtu	3478.70	173.94
Methane	74-82-8	2	0.0081	lb/MMBtu	0.17	0.01
Nitrous oxide	10024-97-2	---	0	lb/MMBtu	0.00	0.00
CO_2e	N/A	5	---	---	3482.97	174.15

Total Criteria :	**4.14**	**T/yr**
Total HAPs:	**0.0019**	**T/yr**

Notes: 1. 40 CFR 60 Subpart IIII, Table 4 for new engines rated greater than 750 horsepower
2. AP-42 Table 3.4-1 (10/96)
3. AP-42 Table 3.4-3 (10/96)
4. AP-42 Table 3.4-4 (10/96)
5. 40 CFR 98 Table A-1
6. 40 CFR 89.112 Table 1 for new engines rated greater than 560 kW
7. The most conservative representation for criteria pollutants among firepump engines and generator engines has been reported in the site-wide totals on Table N-1.

COMBUSTION SOURCES POTENTIAL TO EMIT GREENHOUSE GASES

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

Combustion-Related Greenhouse Gas Emissions

Combustion Source Emission Unit ID	Combustion Source Description	hp	Btu/hp-hr	MMBtu/hr	Annual Operating Hours	Annual Fuel Usage MMBtu/yr	CO_2 [a] Emissions short T/yr	CH_4 [a] Emissions short T/yr	N_2O [a] Emissions short T/yr	CO_2e [b] short T/yr	GHG Mass [c] short T/yr
S012	Regen Gas Heater	---	---	9.7	8,760	84,972.00	4,969.85	0.0937	0.0094	4,974.98	4,969.95
S013	Cryo HMO Heater	---	---	26.3	8,760	230,388.00	13,474.94	0.2540	0.0254	13,488.86	13,475.22
S016	Hot Oil Heater	---	---	61.6	8,760	539,440.80	31,550.83	0.5946	0.0595	31,583.42	31,551.49
S017	Hot Oil Heater	---	---	61.6	8,760	539,440.80	31,550.83	0.5946	0.0595	31,583.42	31,551.49
S018	Hot Oil Heater	---	---	61.6	8,760	539,440.80	31,550.83	0.5946	0.0595	31,583.42	31,551.49
S019	Hot Oil Heater	---	---	61.6	8,760	539,440.80	31,550.83	0.5946	0.0595	31,583.42	31,551.49
S052	Hot Oil Heater	---	---	61.6	8,760	539,440.80	31,550.83	0.5946	0.0595	31,583.42	31,551.49
S053	Hot Oil Heater	---	---	61.6	8,760	539,440.80	31,550.83	0.5946	0.0595	31,583.42	31,551.49
S056	Stabilizer Heater	---	---	10.1	8,760	88,388.40	5,169.66	0.0974	0.0097	5,175.00	5,169.77
S001	Hot Oil Heater	---	---	216.7	8,760	1,898,292.00	111,027.37	2.0925	0.2092	111,142.04	111,029.68
S024	Regen Gas Heater	---	---	9.7	8,760	84,972.00	4,969.85	0.0937	0.0094	4,974.98	4,969.95
S026	Cryo HMO Heater	---	---	26.3	8,760	230,388.00	13,474.94	0.2540	0.0254	13,488.86	13,475.22
S036	Regen Gas Heater	---	---	9.7	8,760	84,972.00	4,969.85	0.0937	0.0094	4,974.98	4,969.95
S037	Cryo HMO Heater	---	---	26.3	8,760	230,388.00	13,474.94	0.2540	0.0254	13,488.86	13,475.22
S040	Regen Gas Heater	---	---	19.3	8,760	168,892.80	9,878.21	0.1862	0.0186	9,888.41	9,878.41
S041	Cryo HMO Heater	---	---	54.7	8,760	478,909.20	28,010.46	0.5279	0.0528	28,039.39	28,011.04
S044	Regen Gas Heater	---	---	9.7	8,760	84,972.00	4,969.85	0.0937	0.0094	4,974.98	4,969.95
S045	Cryo HMO Heater	---	---	26.3	8,760	230,388.00	13,474.94	0.2540	0.0254	13,488.86	13,475.22
S048	Regen Gas Heater	---	---	9.7	8,760	84,972.00	4,969.85	0.0937	0.0094	4,974.98	4,969.95
S049	Cryo HMO Heater	---	---	26.3	8,760	230,388.00	13,474.94	0.2540	0.0254	13,488.86	13,475.22
S034	Flare (Pigging)	---	---	170.7	---	1,707.12	118.31	0.0019	0.0002	118.41	118.31

CO_2, CH_4, or N_2O = Fuel * HHV * EF (Eq. C-1, §98.33(a)(1)(i) and C-8, §98.33(c)(1))

Where:

CO_2, CH_4, or N_2O = annual emissions from combustion, kg

Fuel = volume of fuel combusted, scf/yr

HHV = high heat value of fuel, MMBtu/scf

EF = emission factors from Tables C-1 and C-2 of 40 CFR 98, Subpart C are as follows:

	Natural Gas	Propane
CO_2 =	53.06 kg/MMBtu	62.87 kg/MMBtu
CH_4 =	0.001 kg/MMBtu	0.001 kg/MMBtu
N_2O =	0.0001 kg/MMBtu	0.0001 kg/MMBtu

[a] The unit design rating in MMBtu/hr was substituted for Fuel and HHV in Equation C-1 and a conversion from metric tons to short tons was applied, as shown in the following example calculation for Emissions Unit ID S012:

CO_2 (short T/yr) = (0.001 metric T/kg) * (Fuel Usage, MMBtu/yr) * (CO_2 EF, kg/MMBtu) * (2,204.6 lb/metric T) / (2,000 lb/short T)

= 4,969.85 short T/yr

[b] An example calculation for CO_2e using Eq. A-1 and global warming potential factors found in Table A-1 follows:

CO_2e (short T/yr) = (CO_2 Emissions, short T/yr) + 25 * (CH_4 Emissions, short T/yr) + 298 * (N_2O Emissions, short T/yr)

= 4,974.98 short T/yr

[c] An example calculation for GHG Mass in short T/yr for Emission Unit ID S012 follows:

GHG Mass (short T/yr) = (CO_2 Emissions, short T/yr) + (CH_4 Emissions, short T/yr) + (N_2O Emissions, short T/yr)

= 4,969.95 short T/yr

Waste gas combustion GHG emissions from the flare are calculated on the following sheet.

GREENHOUSE GAS EMISSIONS FROM FLARE WASTE GAS COMBUSTION

AIR PERMIT APPLICATION

NATRIUM EXTRACTION AND FRACTIONATION PROCESSING PLANT

BLUE RACER MIDSTREAM, LLC

CO_2 Combustion Emissions

	Number of Carbon Atoms	Molecular Weight lb/lbmol	Closed Vent System (Area 2) [a] Hourly (lb/hr)	Closed Vent System (Area 2) [a] Annual (T/yr)	Closed Vent System (Area 1) [a] Hourly (lb/hr)	Closed Vent System (Area 1) [a] Annual (T/yr)	Maintenance and Blowdowns Hourly (lb/hr)	Maintenance and Blowdowns Annual (T/yr)	Irregular Process Vents Hourly (lb/hr)	Irregular Process Vents Annual (T/yr)	Ethane Amine Flash Tanks Hourly (lb/hr)	Ethane Amine Flash Tanks Annual (T/yr)	Total Emissions Hourly (lb/hr)	Total Emissions Annual (T/yr)	Total CO_2 Emissions CO_2 Hourly (lb/hr)	Total CO_2 Emissions CO_2 Annual (T/yr)
Compound																
Methane	1	16.043	0.6233	2.7300	17.4889	76.6015	1,509.5512	1,242.8371	8.8507	73.3621	0.3012	1.3193	1,536.8153	1,396.8500	4,172.7654	3,792.7312
Ethane	2	30.07	0.1728	0.7568	4.8051	21.0462	3,068.2884	534.1769	4.4974	41.3045	81.7582	358.1009	3,159.5219	955.3853	9,153.8925	2,767.9802
Propane	3	44.097	0.3134	1.3726	3.4032	14.9062	154.1794	65.8729	2.1075	12.3353	0.9592	4.2013	160.9627	98.6884	472.1894	289.5055
i-Butane	4	58.123	0.0239	0.1046	0.6337	2.7756	39.9751	17.0793	0.5464	3.1983	0.0000	0.0000	41.1791	23.1578	122.1989	68.7207
n-Butane	4	58.123	0.0330	0.1447	0.9173	4.0178	58.9831	25.2004	0.8063	4.7190	0.0000	0.0000	60.7397	34.0820	180.2449	101.1382
i-Pentane	5	72.15	0.0120	0.0526	0.3369	1.4757	22.0915	9.4386	0.3020	1.7675	0.0000	0.0000	22.7424	12.7344	67.9594	38.0532
n-Pentane	5	72.15	0.0092	0.0403	0.2584	1.1316	14.9732	6.3973	0.2047	1.1980	0.0000	0.0000	15.4454	8.7672	46.1544	26.1982
n-Hexane	6	86.172	0.0084	0.0368	0.2358	1.0329	19.6346	8.3889	0.2684	1.5709	0.0000	0.0000	20.1473	11.0295	60.4895	33.1147
Heptane	7	100.198	0.0035	0.0152	0.0976	0.4275	11.4125	4.8760	0.1560	0.9131	0.0000	0.0000	11.6696	6.2318	35.1538	18.7730
Benzene	6	78.00	0.0001	0.0002	0.0015	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0016	0.0068	0.0052	0.0227
Toluene	7	92.13	0.0001	0.0003	0.0021	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0022	0.0095	0.0071	0.0312
Ethylbenzene	8	106.165	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Xylene	8	106.165	0.0000	0.0001	0.0007	0.0033	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0034	0.0025	0.0110
Octane	8	114.224	0.0018	0.0079	0.0506	0.2215	4.3330	1.8513	0.0592	0.3467	0.0000	0.0000	4.4446	2.4273	13.4229	7.3305
												Total CO_2 Emissions:			**14,324.4859**	**7,143.6103**

Sample calculation CO_2 combustion (using methane):

CO_2 Hourly= (Total Waste Gas Emissions, lb/hr CH_4) * (Destruction Efficiency) * (No. of C, lbmol C/lbmol CH_4) * (44 lb CO_2/lbmol C) / (MW, lb CH_4/lbmol CH_4)

= (1,536.8153 lb/hr CH4) * (0.99) * (1 lbmol C/lbmol CH4) * (44 lb CO2/lbmol C) / (16.04 lb CH4/lbmol CH4)

= 4,172.7654 lb/hr CO_2

CO_2 Annual = (Total Waste Gas Emissions, T/yr CH_4) * (Destruction Efficiency) * (No. of C, lbmol C/lbmol CH_4) * (44 lb CO_2/lbmol C) / (MW, lb CH_4/lbmol CH_4)

= (1396.8500 T/yr H4) * (0.99) * (1 lbmol C/lbmol CH4) * (44 lb CO2/lbmol C) / (16.04 lb CH4/lbmol CH4)

= 3,792.7312 T/yr CO_2

N_2O = Fuel * HHV * 0.0001 (Eq. W-40, §98.233(z)(6))

Where:

N_2O = annual emissions from combustion, kg

Fuel = volume of fuel combusted, scf/yr

HHV = high heat value of fuel, MMBtu/scf

N_2O Combustion Emissions

	Closed Vent System (Area 2) [a]	Closed Vent System (Area 1) [a]	Maintenance and Blowdowns	Irregular Process Vents	Ethane Amine Flash Tanks
Waste Gas Flow (scf/yr)	177,248.21	4,559,635.92	99,334,240.00	5,000,000.00	1051.56
Heating Value (Btu/scf)	1,234.15	1,136.36	1,242.74	1,528.61	1,761.18
N_2O Emissions (T/yr)	**0.00002**	**0.0006**	**0.014**	**0.001**	**0.0000002**

Sample Calculation for Closed Vent System (Area 2) Emissions:

N_2O = (0.0001 kg N_2O/MMBtu) * (Waste Gas Flow, scf/yr) * (Heating Value, Btu/scf) / (10^6 Btu/MMBtu) / (0.4536 kg/lb) / (2,000 lb/T)

= (0.0001 kg N2O/MMBtu) * (177,248.21 scf/yr) * (1,234.15 Btu/scf) / (10^6 Btu/MMBtu) / (0.4536 kg/lb) / (2,000 lb/T)

= 0.00002 T/yr

Emission Summary:

	Closed Vent System (Area 2) [a] Uncombusted CO_2 (T/yr)	Closed Vent System (Area 2) [a] Uncombusted CH_4 (T/yr)	Closed Vent System (Area 1) [a] Uncombusted CO_2 (T/yr)	Closed Vent System (Area 1) [a] Uncombusted CH_4 (T/yr)	Maintenance and Blowdowns Uncombusted CO_2 (T/yr)	Maintenance and Blowdowns Uncombusted CH_4 (T/yr)	Irregular Process Vents Uncombusted CO_2 (T/yr)	Irregular Process Vents Uncombusted CH_4 (T/yr)	Ethane Amine Flash Tanks Uncombusted CO_2 (T/yr)	Ethane Amine Flash Tanks Uncombusted CH_4 (T/yr)	Total Emissions Uncombusted CO_2 (T/yr)	Total Emissions Uncombusted CH_4 (T/yr)	**Combustion CO_2 (T/yr)**	**Combustion N_2O (T/yr)**	**CO_2e^b (T/yr)**
	0.04	0.03	1.16	0.81	6.00	12.43	0.36	0.73	1.33	0.01	8.90	14.02	7,143.61	0.015	7,507.43

[a] Closed Vent System from Area 2 and Area 1 were taken from Closed Vent System Feed Rate To Flare worksheet.

[b] Total GHG emissions from flare waste gas combustion are calculated as follows:

(8.90 T/yr Uncombusted CO2) + (7,143.61 T/yr Combustion CO2) + ((14.02 T/yr Methane) * 25) + ((0.015 T/yr N2O) * 298) = 7,507.43 T/yr CO2e

Table N.1 - Facility-wide PTE Summary

EU ID	Unit Description	Key Assumptions	Capacity	Capacity Unit	Emission Controls	Potential Annual Emissions (tpy)												
						NO_X	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Lead	Sulfuric Acid Mist	Formaldehyde	Ammonia	Total HAPs	CO_2e
TB1	Turbine #1	Scenario A : LM6000PG-SPRINT (Case 100) Steady-State: -NOx 2 ppmvd@15%O2 w/ SCR -CO 2 ppmvd@15%O2 w/ OxCat -VOC 1 ppmvd w/ OxCat -NH3 slip = 5 ppm Scenario B: SGT-800 Steady State: -NOx 95% control w/ SCR (1.75 ppmvd@15%O2) -CO 90% control w/ OxCat (0.5 ppmvd@15%O2) -VOC 90% control w/ OxCat (0.5 ppmvd@15%O2) -NH3 slip = 5 ppmvd	Scenario A: 482.6 Scenario B: 496.2	MMBtu/hr	SCR + OxCat	20.35	10.74	16.91	16.91	16.91	7.39	1.97	-	0.37	1.50	14.65	2.17	313,792
TB2	Turbine #2		Scenario A: 482.6 Scenario B: 496.2	MMBtu/hr	SCR + OxCat	20.35	10.74	16.91	16.91	16.91	7.39	1.97	-	0.37	1.50	14.65	2.17	313,792
TB3	Turbine #3		Scenario A: 482.6 Scenario B: 496.2	MMBtu/hr	SCR + OxCat	20.35	10.74	16.91	16.91	16.91	7.39	1.97	-	0.37	1.50	14.65	2.17	313,792
TB4	Turbine #4		Scenario A: 482.6 Scenario B: 496.2	MMBtu/hr	SCR + OxCat	20.35	10.74	16.91	16.91	16.91	7.39	1.97	-	0.37	1.50	14.65	2.17	313,792
TB1-TB4	WHRU #1-4	Steady-State: -NOx 2 ppmvd@15%O2 w/ SCR -CO 2 ppmvd@15%O2 w/ OxCat -VOC 1 ppmvd w/ OxCat -NH3 slip = 5 ppm Operating Hours = 1,745 hr/yr each	4 x 475.1	MMBtu/hr	SCR + OxCat	12.22	7.44	12.76	12.76	12.76	0.98	0.45	8.13E-04	0.05	0.12	3.88	0.15	194,160
FH1	Fuel Gas Heater #1	AP-42 EFs	9.9	MMBtu/hr	Low NOX Burners	2.13	3.57	0.32	0.32	0.32	0.03	0.23	2.13E-05	-	3.19E-03	-	4.03E-03	5,078
FH2	Fuel Gas Heater #2	AP-42 EFs	9.9	MMBtu/hr	Low NOX Burners	2.13	3.57	0.32	0.32	0.32	0.03	0.23	2.13E-05	-	3.19E-03	-	4.03E-03	5,078
EG1	Emergency Generator	NSPS III Certified, 100 hrs/yr	1,676	hp	N/A	0.82	0.61	0.04	0.04	0.04	0.17	0.28	-	-	6.92E-04	-	2.27E-03	96
FP1	Fire Pump	Similar Engine, 100 hrs/yr	700	hp	N/A	0.21	0.25	0.02	0.02	0.02	7.18E-02	7.31E-02	-	-	2.89E-04	-	9.49E-04	40
OT1	Lubricating Oil Tank #1	Modeled as Residual Oil #6	5,000	gallons	N/A	-	-	-	-	-	-	1.24E-03	-	-	-	-	1.24E-03	-
OT2	Lubricating Oil Tank #2	Modeled as Residual Oil #6	5,000	gallons	N/A	-	-	-	-	-	-	1.24E-03	-	-	-	-	1.24E-03	-
OT3	Lubricating Oil Tank #3	Modeled as Residual Oil #6	5,000	gallons	N/A	-	-	-	-	-	-	1.24E-03	-	-	-	-	1.24E-03	-
OT4	Lubricating Oil Tank #4	Modeled as Residual Oil #6	5,000	gallons	N/A	-	-	-	-	-	-	1.24E-03	-	-	-	-	1.24E-03	-
OT5	Waste Oil Tank #1	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	6.22E-05	-	-	-	-	6.22E-05	-
OT6	Waste Oil Tank #2	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	6.22E-05	-	-	-	-	6.22E-05	-
OT7	Waste Oil Tank #3	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	6.22E-05	-	-	-	-	6.22E-05	-
OT8	Waste Oil Tank #4	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	6.22E-05	-	-	-	-	6.22E-05	-
FT1	Generator Fuel Tank	Modeled as Fuel Oil #2	25	gallons	N/A	-	-	-	-	-	-	2.45E-05	-	-	-	-	2.45E-05	-
FT2	Fire Pump Fuel Tank	Modeled as Fuel Oil #2	25	gallons	N/A	-	-	-	-	-	-	2.45E-05	-	-	-	-	2.45E-05	-
WS1	Washout Sump #1	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	5.77E-05	-	-	-	-	5.77E-05	-
WS2	Washout Sump #2	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	5.77E-05	-	-	-	-	5.77E-05	-
WS3	Washout Sump #3	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	5.77E-05	-	-	-	-	5.77E-05	-
WS4	Washout Sump #4	Modeled as Residual Oil #6	250	gallons	N/A	-	-	-	-	-	-	5.77E-05	-	-	-	-	5.77E-05	-
GT1	Glycol Tank #1	Modeled as propylene glycol	1,000	gallons	N/A	-	-	-	-	-	-	9.27E-05	-	-	-	-	9.27E-05	-
GT2	Glycol Tank #2	Modeled as propylene glycol	1,000	gallons	N/A	-	-	-	-	-	-	9.27E-05	-	-	-	-	9.27E-05	-
GT3	Glycol Tank #3	Modeled as propylene glycol	1,000	gallons	N/A	-	-	-	-	-	-	9.27E-05	-	-	-	-	9.27E-05	-
GT4	Glycol Tank #4	Modeled as propylene glycol	1,000	gallons	N/A	-	-	-	-	-	-	9.27E-05	-	-	-	-	9.27E-05	-
AT1	Ammonia Tank	Assumes 1 turnover per month	60,000	gallons	N/A	-	-	-	-	-	-	-	-	-	-	15.28	-	-
EL1	Equipment Leaks	-250 Components in GV Service - Oil & Gas Production Operations Average Emission Factors	-	N/A	N/A	-	-	-	-	-	-	0.02	-	-	-	-	5.65E-04	-
					Project Total	98.92	58.40	81.09	81.09	81.09	30.83	9.17	8.55E-04	1.53	6.13	77.75	8.83	1,459,618
					Relevant PSD Major Source Threshold (MST)	100	100	100	100	100	100	100	100	100	-	-	-	-

Emission rates highlighted green originate from Scenario A: LM6000-SPRINT indicating that for this particular pollutant, potential emissions for Scenario A are greater than Scenario B.

Emission rates highlighted blue originate from Scenario B: SGT-800 indicating that for this particular pollutant, potential emissions for Scenario B are greater than Scenario A.

Table N.2 - LM6000PG Turbine Potential Emissions Summary

DIMENSIONAL ANALYSIS

Mass Conversion	0.4536	kg/lb	*NIST SP1038*
Mass Conversion	2,000	lb/ton	*NIST SP1038*
Time Conversion	24	hr/day	
Molecular Weight of HCl	36.5	lb/lbmol	
Molecular Weight of SO_2	64	lb/lbmol	
Molecular Weight of NH_3	17	lb/lbmol	
Molecular Weight of Sulfur	32	lb/lbmol	
Molecular Weight of NO_2	46	lb/lbmol	
Molecular Weight of VOC	12	lb/lbmol (as carbon)	
Molecular Weight of CO	28	lb/lbmol	
Molar Volume @STP	385.2	scf/lbmol	
GWP - CO_2	1	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - CH_4	25	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - N_2O	298	GWP	*40 CFR 98 Subpart A, Table A-1*

OPERATING PARAMETERS

Fuel Used	Natural Gas or C2		
Maximum Heat Input	482.6	MMBtu/hr	
Steady State Operating Hours	8,736	hrs/yr	*= 8,760 (hr/yr) - Startup Hours (hr/yr) - Shutdown Hours (hr/yr)*
Cold Startup Hours	12	hrs/yr	*Engineering Estimate*
Shutdown Hours	12	hrs/yr	*Engineering Estimate*

UNCONTROLLED LM6000PG EMISSION GUARANTEES

VOC	11.0	ppmvd	
NO_X	25.0	ppmvd at 15% O2	
CO	94.0	ppmvd at 15% O2	*At baseload*
CO	150.0	ppmvd at 15% O2	*At minimum turndown rate*

CONTROLLED LM6000PG EMISSION GUARANTEES

VOC	1.0	ppmvd	
NO_X	2.0	ppmvd at 15% O2	*With SCR*
CO	2.0	ppmvd at 15% O2	*With CatOx*

LM6000PG OPERATING PARAMETERS [a]

Temperature Range (deg F)	Heat Input Rate based on HHV (MMBtu/hr)	Fuel Usage (lb/hr)	Fuel Usage (scf/hr)	Exhaust Flow (scfm)	Exhaust Flow (acfm)	Exhaust Temp (deg F)	Moisture Content (%)	Oxygen Content (%)
59	482.6	22,939.5	487,704	252,569	657,315	901	8.23	13.77

[a] *Performance information provided by GE at ISO conditions (i.e., 59F, 60% humidity, and 1 atm)*

POTENTIAL EMISSIONS

Pollutant	Emission Factor Value	Emission Factor Units	Emission Factor Notes	Emission Rates (lb/hr) Steady State	Startup	Shutdown	Maximum Short Term Emissions (lb/hr)	Maximum Annual Emissions (tpy)
PM [a,b]	0.01	lb/MMBtu	AP-42 Table 3.1-2a	3.86	3.19	3.19	3.86	16.91
PM_{10} [a,b]	0.01	lb/MMBtu	AP-42 Table 3.1-2a	3.86	3.19	3.19	3.86	16.91
$PM_{2.5}$ [a,b]	0.01	lb/MMBtu	AP-42 Table 3.1-2a	3.86	3.19	3.19	3.86	16.91
SO_2 [c]	3.40E-03	lb/MMBtu	AP-42 Table 3.1-2a		1.64		1.64	7.19
VOC [d,e]	1.0	ppmvd	Vendor Guarantee	0.44	4.81	4.81	4.81	1.97
NO_X [f,g]	2.0	ppmvd at 15% O2	Vendor Guarantee	3.35	41.86	41.86	41.86	15.13
CO [f,g]	2.0	ppmvd at 15% O2	Vendor Guarantee	2.04	152.90	95.82	152.90	10.40
Ammonia [h]	5.0	ppm	Assumed Ammonia Slip	3.34	-	3.34	3.34	14.65
Sulfuric Acid Mist	1.70E-04	lb/MMBtu	5% of SO_2		0.08		0.08	0.36
HAP								
Acetaldehyde	4.00E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.02		0.02	0.08
Acrolein	6.40E-06	lb/MMBtu	AP-42 Table 3.1-3.		0.00		0.00	0.01
Benzene	1.20E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.01		0.01	0.03
1,3-Butadiene	4.30E-07	lb/MMBtu	AP-42 Table 3.1-3.		0.00		0.00	0.00
Ethylbenzene	3.20E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.02		0.02	0.07
Formaldehyde	7.10E-04	lb/MMBtu	AP-42 Table 3.1-3.		0.34		0.34	1.50
Naphthalene	1.30E-06	lb/MMBtu	AP-42 Table 3.1-3.		0.00		0.00	0.00
Proplylene Oxide	2.90E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.01		0.01	0.06
Toluene	1.30E-04	lb/MMBtu	AP-42 Table 3.1-3.		0.06		0.06	0.27
o-Xylene	6.40E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.03		0.03	0.14
Total HAPs [c]	1.03E-03	lb/MMBtu			0.49		0.49	2.17
Greenhouse Gases [i]								
CO_2	5.31E+01	kg/MMBtu	40 CFR 98, Table C-1 for NG		56,453.23		56,453.23	247,265.16
CH_4	1.00E-03	kg/MMBtu	40 CFR 98, Table C-2 for NG		1.06		1.06	4.66
N_2O	1.00E-04	kg/MMBtu	40 CFR 98, Table C-2 for NG		0.11		0.11	0.47
CO_2e [j]	-	-	-		-		-	247,520.54

[a] *PM/PM10/PM2.5 Emissions (lb/hr) = Heat Input (MMBtu/hr) × Emission Factor (lb/MMBtu) + Additional PM from SCR/OxCat (lb/hr)*

[b] *PM/PM10/PM2.5 Emissions During Startup (lb/hr) = Heat Input (MMBtu/hr) × Emission Factor (lb/MMBtu)*
Assumes SCR and OxCat are not fully functional during the startup since the temperature has not risen to the threshold for these equipment to become effective.
Shutdown emissions are conservatively set equal to startup emissions.

[c] *SO_2 or HAPs Emissions (lb/hr) = Maximum Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)*
SO_2 or HAPs Emissions (tpy) = Maximum Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8,760 (hr/yr) / 2,000 (lb/ton)

[d] *VOC Emissions (lb/hr) = VOC (ppmvd) x [1 - Moisture Content / 100] x 2,116.8 (lb/sq.ft) x Exhaust Flow Rate (acfm) x Molecular Weight of VOC (lb/lbmol) x 60 (min/hr) / [1,545 x (Exhaust Temperature (F) + 460) x 1,000,000]*
Based on operation at 100% load, 60% relative humidity, and 14.7 psi (2,116.8 lb/sq. ft) pressure. Assumes the exhaust behaves as an ideal gas, with universal gas constant, R, of 1,545 ft-lb/°R.
Conversion from Temp (F) to Temp (Rankine) = Temp (F) + 460

[e] *VOC Emissions During Startup assumes 11 ppmvd instead of 1 ppmvd since the OxCat won't be fully functional until a certain temperature is reached.*
Shutdown emissions are conservatively set equal to startup emissions.

[f] *NOX or CO Emissions (lb/hr) = NOX or CO (ppmvd) x [20.9 x (1 - Moisture Content / 100) - Oxygen Content] / [20.9 - 15] x 2,116.8 (lb/sq.ft) x Exhaust Flow Rate (acfm) x Molecular Weight of NOX or CO (lb/lbmol) x 60 (min/hr) / [1,545 x (Exhaust Temperature (F) + 460) x 1,000,000]*
Based on 20.9% O2 in air and derived from Equation 19-1 of 40 CFR 60, Appendix A-7, Method 19.
Based on operation at 100% load, 60% relative humidity, and 14.7 psi (2,116.8 lb/sq. ft) pressure. Assumes the exhaust behaves as an ideal gas, with universal gas constant, R, of 1,545 ft-lb/°R.
Conversion from Temp (F) to Temp (Rankine) = Temp (F) + 460

[g] *NOX Emissions During Startup assumes 25 ppmvd instead of 2 ppmvd since the SCR won't be fully functional until a certain temperature is reached.*
NOX shutdown emissions are conservatively set equal to startup emissions.
CO Emissions During Startup assumes 150 ppmvd instead of 2 ppmvd since the OxCat won't be fully functional until a certain temperature is reached.
CO Emissions During shutdown assumes 94 ppmvd instead of 2 ppmvd assuming OxCat would lose efficiency as the turbine shuts down.

[h] *Ammonia Emissions (lb/hr) = Ammonia (ppm) x Exhaust Flow Rate (scfm) x Molecular Weight of Ammonia (lb/lbmol) x 60 (min/hr) / [Molar Volume @ STP (lbmol/scf) x 1,000,000]*

[i] *GHG Emission Rate (lb/hr) = Heat Input (MMBtu/hr) × Emission Factor (kg/MMBtu) / 0.45359237 (kg/lb)*
GHG Emission Rate (tpy) = Heat Input (MMBtu/hr) × Emission Factor (kg/MMBtu) × 8,760 (hr/yr) / 0.45359237 (kg/lb) / 2,000 (lb/ton)

[j] *CO_2e Emissions (tpy) = Annual CO_2 Emission (tpy) x CO_2 GWP + Annual CH_4 Emissions (tpy) x CH_4 GWP + Annual N_2O Emissions (tpy) x N_2O GWP*

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**
Engine:	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**	**LM6000**
Model:	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**	**PG-SPRINT**
Options:	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Generator	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**	**BDAX 7-29**
Frequency,Hz	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**
Voltage,kV	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**	**13.8**
PF	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**	**0.85**
	P50	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**	**P50**
Ambient Conditions																
Dry Bulb Temp., °F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
Wet Bulb Temp., °F	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39
Relative Humidity, %	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Elevation a.s.l., ft	655	655	655	655	655	655	655	655	655	655	655	655	655	655	655	655
Barometric Press., psi	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351
Pressure Losses																
Inlet Press. Loss, inH2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exh. Press. Loss, inH2O	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Volute Loss, inH2O	4.31	4.26	4.01	3.83	3.6	3.35	3.17	3.01	2.82	2.58	2.53	2.53	2.53	2.54	2.54	2.54
GTG Load, %	**100**	**100**	**94**	**89**	**84**	**79**	**74**	**69**	**63**	**58**	**53**	**48**	**43**	**38**	**33**	**28**
Gen. Output, Gross, kW	**55275**	**52515**	**49148**	**46518**	**43885**	**41251**	**38614**	**35975**	**33335**	**30692**	**28047**	**25400**	**22751**	**20100**	**17447**	**14792**
HR, btu/(kW*h)	**8732**	**8718**	**8734**	**8816**	**8933**	**9100**	**9241**	**9404**	**9594**	**9821**	**10093**	**10451**	**10907**	**11484**	**12254**	**13265**
Guar HR, btu/(kW*h)	**8820**	**8806**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**
STD Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPT Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOP Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gen. Output, Unit Net, kW	55274.5206	52515.4636	49148.473	46517.9417	43885.3935	41250.778	38614.114	35975.4113	33334.6571	30691.8613	28047.0108	25400.1129	22751.1632	20100.1601	17447.1051	14791.988
HR, Net, btu/(kW*h)	8731.764	8718.433	8733.546	8815.659	8932.682	9100.111	9240.701	9404.482	9593.743	9821.345	10092.825	10450.562	10906.765	11484.151	12254.218	13265.159
G-HR, Net, btu/(kW*h)	8819.964	8806.498	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Comp. Inlet Temp., °F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
LP Comp. Inlet Flow, lb/s	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
IGV Angle, °	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Flow																
Fuel Number	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091
Fuel Name	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue
Fuel LHV, BTU/lb	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040
Heat Input, MMBTU/h	482.6	457.9	429.2	410.1	392	375.4	356.8	338.3	319.8	301.4	283.1	265.4	248.1	230.8	213.8	196.2
Fuel Flow, lb/h	22939.5	21761.2	20401.3	19490.9	18631.9	17841.7	16959.3	16080.4	15199.9	14326.8	13454.1	12616.3	11793.9	10971.2	10161.7	9326
Vol. Fuel Flow, scfm	8128.4	7710.9	7229	6906.4	6602.1	6322	6009.4	5698	5386	5076.6	4767.4	4470.5	4179.1	3887.6	3600.7	3304.6
Fuel Temp., °F	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
Pgas@Manifold, psia	577.339	557.68	529.729	510.273	489.034	464.737	443.803	423.919	403.342	381.208	362.205	344.117	325.823	307.608	289.278	270.951
Pgas@B_Plate, psig	694.293	668.917	634.235	610.255	584.658	556.208	530.824	506.536	481.527	454.946	431.592	409.335	386.933	364.614	342.232	319.747
Fuel Nozzle Effective Area,	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029
Total Fuel Nozzle Effective A	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855
Fuel Nozzle Type	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD
Fuel Nozzle Warning																
Fuel consumption for startup																
Energy, MMBTU	25.348	23.742	21.883	20.521	19.219	17.973	16.78	15.644	14.566	13.547	12.585	11.682	10.834	10.04	9.302	8.617
Vol., scf	26795.318	25097.543	23132.101	21692.518	20316.119	18999.344	17737.44	16537.018	15397.919	14320.362	13303.908	12348.631	11452.149	10613.457	9832.662	9108.917
NOx Control	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
Engine:	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000
Model:	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT	PG-SPRINT
Options:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Generator	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29	BDAX 7-29
Frequency,Hz	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Voltage,kV	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
PF	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50
Ambient Conditions																
Dry Bulb Temp., °F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
Wet Bulb Temp., °F	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39
Relative Humidity, %	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Elevation a.s.l., ft	655	655	655	655	655	655	655	655	655	655	655	655	655	655	655	655
Barometric Press., psi	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351	14.351
Pressure Losses																
Inlet Press. Loss, inH2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exh. Press. Loss, inH2O	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Volute Loss, inH2O	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54
GTG Load, %	**23**	**18**	**21**	**19**	**18**	**16**	**14**	**12**	**11**	**9**	**7**	**6**	**4**	**2**	**1**	**0**
Gen. Output, Gross, kW	**12135**	**9476**	**9239**	**8496**	**7752**	**7009**	**6265**	**5521**	**4777**	**4032**	**3288**	**2543**	**1799**	**1054**	**309**	**10**
HR, btu/(kW*h)	**14688**	**16938**	**16765**	**17676**	**18758**	**20053**	**21650**	**23699**	**26410**	**30121**	**35494**	**44014**	**59585**	**97152**	**314629**	**9479103**
Guar HR, btu/(kW*h)	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**
STD Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPT Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOP Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gen. Output, Unit Net, kW	12134.8175	9475.5861	9239.0508	8495.7394	7752.2671	7008.6339	6264.8397	5520.8846	4776.7688	4032.4912	3288.053	2543.4536	1798.6933	1053.7715	308.6885	9.6941
HR, Net, btu/(kW*h)	14687.52	16937.732	16765.173	17675.961	18757.948	20053.344	21649.938	23699.248	26409.533	30120.911	35493.603	44014.376	59585.147	97151.874	314629.374	9479103.23
G-HR, Net, btu/(kW*h)	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Comp. Inlet Temp., °F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
LP Comp. Inlet Flow, lb/s	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
IGV Angle, °	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Flow																
Fuel Number	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091
Fuel Name	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue	QuantumFue
Fuel LHV, BTU/lb	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040
Heat Input, MMBTU/h	178.2	160.5	154.9	150.2	145.4	140.5	135.6	130.8	126.2	121.5	116.7	111.9	107.2	102.4	97.1	91.9
Fuel Flow, lb/h	8471.1	7628.1	7361.9	7137.4	6911.5	6680	6446.5	6218.7	5995.9	5773	5546.8	5320.8	5093.9	4865.8	4616.1	4367.5
Vol. Fuel Flow, scfm	3001.7	2703	2608.6	2529.1	2449	2367	2284.3	2203.5	2124.6	2045.6	1965.5	1885.4	1805	1724.2	1635.7	1547.6
Fuel Temp., °F	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
Pgas@Manifold, psia	252.521	233.789	229.995	224.776	219.59	214.316	208.905	203.555	198.334	193.039	187.717	182.415	177.026	171.148	164.504	157.967
Pgas@B_Plate, psig	297.08	274.153	269.129	262.784	256.469	250.04	243.46	236.967	230.628	224.211	217.754	211.318	204.789	197.739	189.8	181.977
Fuel Nozzle Effective Area,	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029
Total Fuel Nozzle Effective A	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855	0.855
Fuel Nozzle Type	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD	STANDARD
Fuel Nozzle Warning																
Fuel consumption for start																
Energy, MMBTU	7.988	7.417	7.371	7.232	7.097	6.967	6.841	6.719	6.602	6.488	6.379	6.275	6.174	6.078	5.986	5.951
Vol., scf	8444.178	7839.909	7791.509	7644.718	7502.373	7364.505	7231.224	7102.575	6978.446	6858.738	6743.455	6632.664	6526.366	6424.577	6327.326	6290.303
NOx Control	**Water**	**Water**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**	**None**

Table N.3 - LM6000PG Tu

Case	132	133	134
Engine:	LM6000	LM6000	LM6000
Model:	PG-SPRINT	PG-SPRINT	PG-SPRINT
Options:	N/A	N/A	N/A
Generator	BDAX 7-29(	BDAX 7-29(	BDAX 7-290ERJT
Frequency,Hz	60	60	60
Voltage,kV	13.8	13.8	13.8
PF	0.85	0.85	0.85
	P50	P50	P50
Ambient Conditions			
Dry Bulb Temp., °F	59	59	59
Wet Bulb Temp., °F	51.39	51.39	51.39
Relative Humidity, %	60	60	60
Elevation a.s.l., ft	655	655	655
Barometric Press., psi	14.351	14.351	14.351
Pressure Losses			
Inlet Press. Loss, inH2O	4.5	4.5	4.5
Exh. Press. Loss, inH2O	12	12	12
Volute Loss, inH2O	2.54	2.54	2.54
GTG Load, %	0	0	0
Gen. Output, Gross, kW	-28	-28	-28
HR, btu/(kW*h)	-3236310	-3149354	-3149354
Guar HR, btu/(kW*h)	-999	-999	-999
STD Aux Load, kW	0	0	0
OPT Aux Load, kW	0	0	0
BOP Aux Load, kW	0	0	0
Gen. Output, Unit Net, kW	-27.5909	-28.3366	-28.3366
HR, Net, btu/(kW*h)	-3236309.8	-3149353.6	-3149353.6
G-HR, Net, btu/(kW*h)	-999	-999	-999
Comp. Inlet Temp., °F	59	59	59
LP Comp. Inlet Flow, lb/s	N/A	N/A	N/A
IGV Angle, °	N/A	N/A	N/A
Fuel Flow			
Fuel Number	801-1091	801-1091	801-1091
Fuel Name	QuantumFue	QuantumFue	QuantumFuel
Fuel LHV, BTU/lb	21040	21040	21040
Heat Input, MMBTU/h	89.3	89.2	89.2
Fuel Flow, lb/h	4244	4241.6	4241.6
Vol. Fuel Flow, scfm	1503.8	1503	1503
Fuel Temp., °F	180	180	180
Pgas@Manifold, psia	154.768	154.712	154.712
Pgas@B_Plate, psig	178.143	178.074	178.074
Fuel Nozzle Effective Area,	0.029	0.029	0.029
Total Fuel Nozzle Effective A	0.855	0.855	0.855
Fuel Nozzle Type	STANDARD	STANDARD	STANDARD
Fuel Nozzle Warning			
Fuel consumption for start			
Energy, MMBTU	5.946	5.946	0
Vol., scf	6285.935	6285.85	0
NOx Control	None	None	None

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	100	101	102	103	104	105	106	107	108	109	110	111	112	113	114	115
Diluent Injection																
Diluent Flow, lb/h	28955	30302	26994	25004	23303	21712	20001	18368	16800	15252	13697	12275	10889	9639	8410	7204
Diluent Temp., °F	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Sprint Location	LPC	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Sprint Water Flow, lb/h	6805.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sprint Water Temp., °F	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Exhaust Parameters																
Exhaust Temp., °F	900.94	884.55	868.06	862.25	865.66	886.11	886.77	884.1	883.86	891.73	883.44	874.6	868.34	860.37	854.59	843.44
Exhaust Flow, lb/s	309.5	305.8	296	288.3	277.5	261.9	251.9	243	233.3	221.6	213.7	206.3	198.3	190.4	182	174.1
Energy (Ref 0R), BTU/s	110287	107022	101945	98660	95151	91294	87748	84366	80880	77205	73837	70638	67434	64206	60991	57669
Energy (Ref T2), BTU/s	69599	67002	63303	61080	59005	57182	54974	52782	50592	48471	46168	43973	41844	39677	37575	35320
Emissions (ESTIMATED, NOT FOR GUARANTEE)																
NOx, Ref % O2, ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CO, Ref % O2, ppmvd	29.5	67.2	43.4	34.3	34.2	34.8	34.6	34.2	34	33	32.4	31.8	30.2	30.3	29.2	28.4
Total Emissions From Startup To Full Load																
Time	10	9.8003	9.5567	9.3663	9.1758	8.9852	8.7944	8.6034	8.4123	8.221	8.0297	7.8381	7.6464	7.4546	7.2626	7.0704
NOx, lb	3.192	3.03	2.844	2.707	2.576	2.451	2.331	2.217	2.109	2.006	1.91	1.819	1.734	1.655	1.581	1.512
CO, lb	2.239	2.123	1.818	1.674	1.564	1.46	1.359	1.263	1.172	1.088	1.01	0.938	0.872	0.814	0.759	0.71
Aero Energy Fuel Number	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091
Hydrogen, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methane, %Volume	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182
Ethane, %Volume	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998
Ethylene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propane, %Volume	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Propylene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butane, %Volume	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Butylene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butadiene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pentane, %Volume	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cyclopentane, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hexane, %Volume	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Heptane, %Volume	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
CarbonMonoxide, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide, %Volume	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Nitrogen, %Volume	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186
Water Vapor, %Volume	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Oxygen, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HydrogenSulfide, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ammonia, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LHV, BTU/lb	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040
HHV, BTU/lb	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294
NOx Scalar	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113
Specific Gravity	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163
MWI, (Btu/SCF)/SQRT(R)	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018
LHV, BTU/scf	995	995	995	995	995	995	995	995	995	995	995	995	995	995	995	995
HHV, BTU/scf	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099
Messages																
Regulator	304	305	0	0	0	0	0	1323	1323	1323	1323	1323	1323	1323	1323	1323

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
Diluent Injection																
Diluent Flow, lb/h	6011	4916	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Diluent Temp., °F	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Sprint Location	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Sprint Water Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sprint Water Temp., °F	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Exhaust Parameters																
Exhaust Temp., °F	828.05	814.1	829.39	824.76	819.45	813.25	807.08	801.61	796.42	791.34	785.55	779.34	773.16	768.92	763.2	756.44
Exhaust Flow, lb/s	166.2	157.8	156.1	153.7	151.3	148.9	146.3	143.8	141.3	138.7	136.1	133.6	131	127.8	124.1	120.4
Energy (Ref 0R), BTU/s	54243	50778	50478	49481	48483	47449	46381	45344	44345	43334	42307	41280	40235	39099	37757	36426
Energy (Ref T2), BTU/s	32947	30602	30667	29985	29295	28571	27831	27123	26446	25766	25069	24370	23663	22935	22069	21201
Emissions (ESTIMATED, N																
NOx, Ref % O2, ppmvd	25	25	87	83.7	80.4	76.9	73.6	70.3	67.1	63.8	60.6	57.3	54	50.8	47.1	43.6
CO, Ref % O2, ppmvd	27	25.8	5	5.3	5.9	6.8	7.7	8.8	10	11.4	13.1	15.8	19.2	23.2	29	36.3
Total Emissions From Star																
Time	6.8781	6.6857	6.6686	6.6148	6.561	6.5072	6.4534	6.3995	6.3457	6.2918	6.2379	6.1841	6.1302	6.0763	6.0223	6.0007
NOx, lb	1.449	1.391	1.387	1.338	1.293	1.251	1.213	1.177	1.144	1.113	1.085	1.06	1.037	1.016	0.998	0.991
CO, lb	0.667	0.629	0.626	0.625	0.623	0.621	0.619	0.617	0.614	0.611	0.608	0.605	0.601	0.597	0.591	0.589
Aero Energy Fuel Number	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091	801-1091
Hydrogen, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methane, %Volume	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182	88.6182
Ethane, %Volume	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998	9.9998
Ethylene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propane, %Volume	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
Propylene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butane, %Volume	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Butylene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butadiene, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pentane, %Volume	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cyclopentane, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hexane, %Volume	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Heptane, %Volume	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
CarbonMonoxide, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide, %Volume	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Nitrogen, %Volume	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186	0.186
Water Vapor, %Volume	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Oxygen, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HydrogenSulfide, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ammonia, %Volume	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LHV, BTU/lb	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040	21040
HHV, BTU/lb	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294	23294
NOx Scalar	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113	1.113
Specific Gravity	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163	0.6163
MWI, (Btu/SCF)/SQRT(R)	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018	50.018
LHV, BTU/scf	995	995	995	995	995	995	995	995	995	995	995	995	995	995	995	995
HHV, BTU/scf	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099	1099
Messages																
Regulator	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323

Table N.3 - LM6000PG Tu

Case	132	133	134
Diluent Injection			
Diluent Flow, lb/h	N/A	N/A	N/A
Diluent Temp., °F	N/A	N/A	N/A
Sprint Location	**OFF**	**OFF**	**OFF**
Sprint Water Flow, lb/h	0	0	0
Sprint Water Temp., °F	60	60	60
Exhaust Parameters			
Exhaust Temp., °F	752.54	752.43	752.43
Exhaust Flow, lb/s	118.7	118.7	118.7
Energy (Ref 0R), BTU/s	35771	35759	35759
Energy (Ref T2), BTU/s	20768	20760	20760
Emissions (ESTIMATED, N			
NOx, Ref % O2, ppmvd	41.8	41.8	41.8
CO, Ref % O2, ppmvd	40.7	40.8	40.8
Total Emissions From Star			
Time	5.998	5.9979	2
NOx, lb	0.99	0.99	0
CO, lb	0.589	0.589	0
Aero Energy Fuel Number	801-1091	801-1091	801-1091
Hydrogen, %Volume	0	0	0
Methane, %Volume	88.6182	88.6182	88.6182
Ethane, %Volume	9.9998	9.9998	9.9998
Ethylene, %Volume	0	0	0
Propane, %Volume	0.61	0.61	0.61
Propylene, %Volume	0	0	0
Butane, %Volume	0.17	0.17	0.17
Butylene, %Volume	0	0	0
Butadiene, %Volume	0	0	0
Pentane, %Volume	0.04	0.04	0.04
Cyclopentane, %Volume	0	0	0
Hexane, %Volume	0.01	0.01	0.01
Heptane, %Volume	0.014	0.014	0.014
CarbonMonoxide, %Volume	0	0	0
Carbon Dioxide, %Volume	0.35	0.35	0.35
Nitrogen, %Volume	0.186	0.186	0.186
Water Vapor, %Volume	0.002	0.002	0.002
Oxygen, %Volume	0	0	0
HydrogenSulfide, %Volume	0	0	0
Ammonia, %Volume	0	0	0
LHV, BTU/lb	21040	21040	21040
HHV, BTU/lb	23294	23294	23294
NOx Scalar	1.113	1.113	1.113
Specific Gravity	0.6163	0.6163	0.6163
MWI, (Btu/SCF)/SQRT(R)	50.018	50.018	50.018
LHV, BTU/scf	995	995	995
HHV, BTU/scf	1099	1099	1099
Messages			
Regulator	1323	1323	1323

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	100	101	102	103	104	105	106	107	108	109	110	111	112	113	114	115
Regulator Definition	Calculated p	Calculated p	A	A	A	A	A	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc
Warning description	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
Error Description	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
Control Parameters																
HPC Shaft Speed, rpm	10764	10715	10611	10562	10511	10433	10375	10323	10271	10216	10133	10026	9926	9812	9683	9564
LPC Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
PS3 (Comp. Disch), psia	463	454	435	421	404	382	366	351	335	317	304	290	277	263	249	235
T3 (Comp. Discharge), °F	1052.1	1077.05	1049.2	1035.62	1023.2	1008.74	993.73	978.51	963.56	948.93	930.78	913.32	896.22	877.98	859.65	839.31
T48 (LPT Inlet), °F	1693.98	1667.51	1631.11	1611.22	1601.59	1609.19	1594.2	1574.92	1556.97	1546.43	1518.56	1489.46	1462.12	1430.88	1400.24	1361.64
T44 (IPT Inlet), °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Comp. Remaining Margin, %	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
T41, °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
LP Shaft Torque (ft*lbf), ft*lb	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PS3 corrected to P2, psi	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
XN25 (rpm)	10763.6	10715.19	10610.56	10562.39	10510.51	10432.88	10374.79	10323.42	10271.28	10216.09	10133.44	10025.74	9925.64	9811.58	9683.26	9564.2
XN25 corrected to T25 (rpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
XN25 corrected to T3 (rpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)																
AR, %	1.212	1.2192	1.2228	1.2248	1.226	1.226	1.2275	1.2293	1.231	1.2323	1.2345	1.2368	1.239	1.2412	1.2434	1.246
N2, %	71.0704	71.492	71.7033	71.8235	71.8907	71.8921	71.9817	72.0857	72.1816	72.2574	72.3917	72.5248	72.6554	72.783	72.913	73.06
O2, %	13.7713	14.2228	14.527	14.7047	14.7759	14.6691	14.7825	14.9403	15.0805	15.1551	15.3806	15.6157	15.8372	16.076	16.311	16.5987
CO2, %	5.7147	5.4823	5.3157	5.2171	5.1813	5.2572	5.1964	5.1073	5.029	4.9928	4.8624	4.7249	4.5966	4.4553	4.3173	4.1456
H2O, %	8.2253	7.5733	7.2238	7.0236	6.9199	6.9492	6.8056	6.6313	6.472	6.3567	6.1251	5.8924	5.6666	5.4396	5.2106	4.9453
SO2, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO, %	0.0031	0.0068	0.0043	0.0033	0.0033	0.0034	0.0033	0.0032	0.0032	0.003	0.0029	0.0028	0.0026	0.0025	0.0023	0.0022
HC, %	0.0002	0.0007	0.0003	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001
NOX, %	0.003	0.0029	0.0028	0.0027	0.0027	0.0027	0.0027	0.0027	0.0026	0.0026	0.0025	0.0025	0.0024	0.0023	0.0022	0.0022
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)																
AR, %	0.97	0.9683	0.9671	0.9664	0.9661	0.9666	0.9662	0.9655	0.965	0.9647	0.9638	0.9629	0.962	0.9611	0.9601	0.959
N2, %	81.1113	80.9655	80.8652	80.8064	80.7843	80.8256	80.789	80.7366	80.6906	80.6682	80.5931	80.5147	80.4416	80.3622	80.2849	80.1896
O2, %	13.7601	14.102	14.3434	14.484	14.5366	14.4385	14.5255	14.6499	14.7592	14.8126	14.9911	15.1776	15.3513	15.54	15.7239	15.9502
CO2, %	4.1517	3.9522	3.8161	3.7363	3.7062	3.7623	3.7125	3.6412	3.5786	3.5481	3.4458	3.339	3.2396	3.1314	3.0261	2.8964
H2O, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO, %	0.0036	0.0077	0.0048	0.0037	0.0037	0.0038	0.0037	0.0036	0.0035	0.0034	0.0032	0.0031	0.0028	0.0027	0.0026	0.0024
HC, %	0.0004	0.0014	0.0006	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003
NOX, %	0.003	0.0029	0.0028	0.0027	0.0027	0.0027	0.0027	0.0026	0.0026	0.0026	0.0025	0.0024	0.0024	0.0023	0.0022	0.0021
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)																
AR, %	0.8464	0.8543	0.8583	0.8606	0.8619	0.8619	0.8636	0.8656	0.8674	0.8688	0.8714	0.874	0.8765	0.879	0.8815	0.8844
N2, %	70.7791	71.4376	71.7726	71.9636	72.0698	72.0697	72.2117	72.3775	72.5305	72.6508	72.8665	73.0807	73.2912	73.4978	73.7087	73.948
O2, %	12.0073	12.4425	12.7306	12.899	12.9684	12.8744	12.9833	13.1331	13.2667	13.3404	13.5539	13.7762	13.9867	14.2126	14.436	14.7087
CO2, %	3.6228	3.4871	3.387	3.3274	3.3064	3.3548	3.3184	3.2642	3.2167	3.1955	3.1155	3.0307	2.9516	2.8639	2.7782	2.671
H2O, %	12.7382	11.7679	11.2442	10.9433	10.7874	10.833	10.6169	10.3536	10.1128	9.9387	9.5872	9.2331	8.8889	8.5418	8.1911	7.7836
SO2, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO, %	0.0031	0.0068	0.0043	0.0033	0.0033	0.0034	0.0033	0.0032	0.0032	0.0031	0.0029	0.0028	0.0026	0.0025	0.0024	0.0022
HC, %	0.0004	0.0012	0.0006	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0002
NOX, %	0.0026	0.0025	0.0025	0.0024	0.0024	0.0024	0.0024	0.0024	0.0023	0.0023	0.0023	0.0022	0.0021	0.0021	0.002	0.0019
Exhaust Parameters																
Sp. Heat, BTU/(lb*°R)	0.282	0.28	0.278	0.277	0.277	0.278	0.278	0.277	0.277	0.277	0.276	0.275	0.274	0.273	0.272	0.271
Exh Mol Wght, lb/lb-mol	27.899	27.993	28.041	28.069	28.084	28.083	28.104	28.127	28.149	28.167	28.198	28.229	28.259	28.289	28.32	28.355

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
Regulator Definition	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc	Corrected Pc
Warning description	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
Error Description	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
Control Parameters																
HPC Shaft Speed, rpm	9456	9341	9335	9304	9271	9237	9201	9166	9131	9096	9059	9025	8988	8939	8885	8815
LPC Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
PS3 (Comp. Disch), psia	221	207	205	200	196	192	188	184	179	175	171	166	162	157	151	146
T3 (Comp. Discharge), °F	817.45	794.34	790.55	783.92	776.98	769.69	762.5	755.28	748.01	740.42	732.7	724.65	716.45	708.36	699.02	689.58
T48 (LPT Inlet), °F	1316.27	1269.68	1287.42	1272.7	1257	1240.13	1223.24	1206.66	1189.77	1172.68	1154.31	1135.14	1115.61	1098.32	1079.69	1059.74
T44 (IPT Inlet), °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Comp. Remaining Margin, %	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
T41, °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
LP Shaft Torque (ft*lbf), ft*lb	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PS3 corrected to P2, psi	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
XN25 (rpm)	9456.49	9341.36	9335.49	9303.83	9270.95	9237.29	9201.36	9165.6	9131.15	9095.6	9058.79	9025	8988.1	8938.77	8884.66	8815.1
XN25 corrected to T25 (rpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
XN25 corrected to T3 (rpm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exh Wght % Wet (NOT FOI																
AR, %	1.2487	1.2514	1.2629	1.2632	1.2635	1.2638	1.264	1.2643	1.2646	1.2649	1.2652	1.2656	1.2659	1.2662	1.2665	1.2668
N2, %	73.2232	73.382	74.0538	74.0687	74.0847	74.1019	74.119	74.1357	74.1527	74.1699	74.1882	74.2074	74.2269	74.2439	74.2621	74.2819
O2, %	16.9312	17.2629	17.5936	17.6751	17.7627	17.8565	17.9501	18.0418	18.1351	18.2292	18.3297	18.4349	18.5416	18.6354	18.7352	18.8441
CO2, %	3.9458	3.7456	3.6578	3.6033	3.5449	3.4822	3.4196	3.3582	3.2959	3.233	3.1657	3.0952	3.0237	2.9609	2.8938	2.8207
H2O, %	4.6469	4.3543	3.4248	3.3829	3.3379	3.2897	3.2415	3.1944	3.1464	3.0981	3.0464	2.9923	2.9374	2.8892	2.8379	2.782
SO2, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO, %	0.002	0.0018	0.0003	0.0004	0.0004	0.0004	0.0005	0.0005	0.0006	0.0007	0.0008	0.0009	0.0011	0.0013	0.0015	0.0019
HC, %	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
NOX, %	0.0021	0.0019	0.0066	0.0063	0.0059	0.0055	0.0052	0.0049	0.0046	0.0043	0.004	0.0037	0.0034	0.0031	0.0028	0.0025
Exh Mole % Dry (NOT FOR																
AR, %	0.9577	0.9564	0.9556	0.9553	0.9549	0.9545	0.9541	0.9538	0.9534	0.953	0.9526	0.9521	0.9517	0.9513	0.9509	0.9505
N2, %	80.0799	79.9708	79.9051	79.8768	79.8464	79.8139	79.7814	79.7497	79.7174	79.6849	79.6503	79.614	79.5772	79.5449	79.5106	79.4731
O2, %	16.2112	16.4705	16.6201	16.6879	16.7605	16.8383	16.9157	16.9916	17.0686	17.1462	17.229	17.3155	17.4032	17.48	17.5618	17.6508
CO2, %	2.7469	2.5983	2.5124	2.4736	2.432	2.3874	2.343	2.2996	2.2554	2.211	2.1635	2.1138	2.0635	2.0193	1.9723	1.921
H2O, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO, %	0.0021	0.0019	0.0004	0.0004	0.0004	0.0005	0.0005	0.0006	0.0006	0.0007	0.0008	0.001	0.0011	0.0013	0.0016	0.002
HC, %	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002
NOX, %	0.002	0.0019	0.0063	0.006	0.0056	0.0053	0.005	0.0047	0.0044	0.0041	0.0038	0.0035	0.0032	0.0029	0.0027	0.0024
Exh Mole % Wet (NOT FOR																
AR, %	0.8876	0.8907	0.9037	0.904	0.9043	0.9047	0.905	0.9054	0.9057	0.9061	0.9065	0.9069	0.9073	0.9076	0.908	0.9084
N2, %	74.2148	74.4752	75.5628	75.5886	75.6162	75.6459	75.6754	75.7044	75.7339	75.7636	75.7953	75.8285	75.8622	75.8918	75.9232	75.9575
O2, %	15.0239	15.3387	15.7169	15.792	15.8726	15.959	16.0452	16.1297	16.2157	16.3024	16.3951	16.4922	16.5907	16.6772	16.7694	16.87
CO2, %	2.5457	2.4198	2.3758	2.3408	2.3031	2.2628	2.2225	2.1829	2.1427	2.1022	2.0588	2.0133	1.9672	1.9266	1.8833	1.836
H2O, %	7.324	6.872	5.4343	5.3685	5.2979	5.2221	5.1466	5.0725	4.9971	4.9211	4.8398	4.7547	4.6684	4.5926	4.5118	4.4237
SO2, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO, %	0.002	0.0018	0.0003	0.0004	0.0004	0.0004	0.0005	0.0006	0.0006	0.0007	0.0008	0.0009	0.0011	0.0013	0.0016	0.0019
HC, %	0.0002	0.0002	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002
NOX, %	0.0018	0.0017	0.006	0.0057	0.0053	0.005	0.0047	0.0044	0.0041	0.0039	0.0036	0.0033	0.0031	0.0028	0.0025	0.0023
Exhaust Parameters																
Sp. Heat, BTU/(lb*°R)	0.27	0.269	0.267	0.267	0.266	0.266	0.266	0.265	0.265	0.265	0.264	0.264	0.264	0.263	0.263	0.263
Exh Mol Wght, lb/lb-mol	28.393	28.431	28.585	28.589	28.593	28.598	28.602	28.607	28.611	28.616	28.621	28.626	28.631	28.636	28.641	28.646

Table N.3 - LM6000PG Tu

Case	132	133	134
Regulator Definition	Corrected Pc	Corrected Pc	Corrected Power less than limit for heat rate guarantee calculation
Warning description	A	A	A
Error Description	A	A	A
Control Parameters			
HPC Shaft Speed, rpm	8773	8772	8772
LPC Speed, rpm	3905	3905	3905
PS3 (Comp. Disch), psia	143	143	143
T3 (Comp. Discharge), °F	684.75	684.65	684.65
T48 (LPT Inlet), °F	1049.12	1048.88	1048.88
T44 (IPT Inlet), °F	N/A	N/A	N/A
Comp. Remaining Margin, %	N/A	N/A	N/A
T41, °F	N/A	N/A	N/A
LP Shaft Torque (ft*lbf), ft*lb	N/A	N/A	N/A
PS3 corrected to P2, psi	N/A	N/A	N/A
XN25 (rpm)	8772.68	8771.75	8771.75
XN25 corrected to T25 (rpm)	N/A	N/A	N/A
XN25 corrected to T3 (rpm)	N/A	N/A	N/A
Exh Wght % Wet (NOT FOI			
AR, %	1.267	1.267	1.267
N2, %	74.2926	74.2928	74.2928
O2, %	18.9027	18.9041	18.9041
CO2, %	2.7812	2.7803	2.7803
H2O, %	2.7519	2.7512	2.7512
SO2, %	0	0	0
CO, %	0.0021	0.0021	0.0021
HC, %	0.0001	0.0001	0.0001
NOX, %	0.0024	0.0024	0.0024
Exh Mole % Dry (NOT FOR			
AR, %	0.9502	0.9502	0.9502
N2, %	79.453	79.4525	79.4525
O2, %	17.6987	17.6998	17.6998
CO2, %	1.8934	1.8927	1.8927
H2O, %	0	0	0
SO2, %	0	0	0
CO, %	0.0022	0.0022	0.0022
HC, %	0.0003	0.0003	0.0003
NOX, %	0.0023	0.0023	0.0023
Exh Mole % Wet (NOT FOR			
AR, %	0.9086	0.9086	0.9086
N2, %	75.9759	75.9763	75.9763
O2, %	16.9242	16.9254	16.9254
CO2, %	1.8105	1.8099	1.8099
H2O, %	4.3762	4.3751	4.3751
SO2, %	0	0	0
CO, %	0.0021	0.0021	0.0021
HC, %	0.0003	0.0003	0.0003
NOX, %	0.0022	0.0022	0.0022
Exhaust Parameters			
Sp. Heat, BTU/(lb*°R)	0.262	0.262	0.262
Exh Mol Wght, lb/lb-mol	28.649	28.649	28.649

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**
Exh. Flow, ACFM	657314.6	639557.5	610455.7	591350.3	570395.9	546554.1	525542.1	505655.2	485024.2	462948.3	443302.8	424640.1	405826.9	386876.7	367909.1	348403.8
Exh. Flow, SCFM	252568.5	248741.1	240371.3	233872.1	225004.6	212322.7	204060.1	196729	188735.2	179096.5	172554.8	166386.1	159763.8	153222.6	146351.8	139778
Shaft Power, Gross, hp	76358.6	72597.5	68011.7	64432.2	60852.6	57273.1	53693.5	50113.9	46534.4	42954.8	39375.2	35795.7	32216.1	28636.5	25057	21477.4
Generator Information																
Gen. Capacity, kW	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5
Gen. Efficiency, %	0.9819	0.9818	0.9816	0.9814	0.9811	0.9808	0.9803	0.9797	0.9789	0.978	0.9768	0.9753	0.9733	0.9708	0.9673	0.9626
Gen. Inlet Temp., °F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
Gearbox Loss, hp	870	870	870	870	870	870	870	870	870	870	870	870	870	870	870	870
Capacity Curve	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374
Efficiency Curve	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376
8th Stage Bleed																
HPC Stg8 Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IBH Bleed Flow, lb/s, lb/s	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HPC Stg8 Bld P, psi	147.498	150.639	144.709	140.171	134.864	128.675	123.544	118.643	113.373	107.494	103.695	101.191	98.074	95.397	93.38	90.36
HPC Stg8 Bld Temp., °F	657.59	690.54	670.48	660.34	651.91	643.89	633.5	623.21	612.56	602.34	591.28	583.35	574.94	566.25	558.66	547.73
CDP Bleed																
HPC CDP Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HPC CDP Bld P, psi	463.37	453.528	434.58	420.796	403.912	382.034	365.883	351.058	335.303	317.396	303.535	290.352	276.656	262.99	248.968	235.137
LPC Inlet Flow Wet, lb/s	297.978	296.176	287.514	280.92	272.507	262.82	255.685	249.036	240.942	230.303	228.357	228.387	228.434	228.475	228.514	228.537
LPC Inlet Flow Dry, lb/s	296.031	294.242	285.636	279.085	270.727	261.103	254.015	247.409	239.368	228.799	226.866	226.895	226.942	226.982	227.021	227.045
Comb. Air Flow, lb/s	210.4	209.2	203	198	190.8	180.1	173.4	167.5	161	153	147.8	142.9	137.5	132.2	126.6	121.2
LPC VBV Bld. Flow, lb/s	0	0	0	0.41	2.255	7.702	9.971	11.626	12.701	13.352	18.672	25.471	32.968	40.403	48.244	55.7
HPC Inlet Press., psi	34.69	36.605	35.982	35.547	34.194	31.194	30.039	29.319	28.407	26.888	26.54	26.431	26.2	25.978	25.697	25.598
T25 (HPC Inlet),, °F	235.472	253.127	245.655	243.037	235.346	215.647	208.492	204.372	199.124	191.231	188.671	187.727	186.773	185.922	185.255	185.42
HPC Inlet Temp., °F	235.321	255.27	247.776	245.992	240.064	223.328	217.239	214.326	210.22	202.863	201.069	200.59	199.616	198.689	197.545	197.104
Comp. Inlet SH, lbm/lbm	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Burner Mode	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Deck	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**	**G0125P_V2**
Card Pack	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**	**8ka.scp**
Ran Modified Input File	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Exhaust Card Pack	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**	**7f5.scp**
Other Options																
Inlet Config.	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**	**Radial**
Exhaust Config.	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**	**Axial**
Inlet Press. Loss Opt.	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed
Exh. Press. Loss Opt	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed
Generator																
Generator Name	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E
Coolant	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air
Run Control Level 1																
Target Power	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F
Target Shaft Power, hp	90000	90000	68011.757	64432.191	60852.625	57273.059	53693.492	50113.926	46534.36	42954.794	39375.228	35795.662	32216.095	28636.529	25056.963	21477.397
Target Electr. Power, kW	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
Target Part Load, %	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Sprint ON/OFF	On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
Exh. Flow, ACFM	328321.6	307887.1	306586.7	300660.4	294740.1	288609.3	282261.1	276083.4	270132.4	264100.6	257972.3	251853.8	245608.4	238777.3	230697.4	222695.1
Exh. Flow, SCFM	133295.6	126368.3	124341.9	122378.2	120466.1	118535.4	116492.3	114437.1	112433.1	110368.8	108309.3	106270	104154.4	101607.2	98627.9	95736.6
Shaft Power, Gross, hp	17897.8	14318.3	14000	13000	12000	11000	10000	9000	8000	7000	6000	5000	4000	3000	2000	1000
Generator Information																
Gen. Capacity, kW	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5	65477.5
Gen. Efficiency, %	0.9557	0.9449	0.9436	0.9392	0.934	0.9278	0.9202	0.9107	0.8984	0.8822	0.8595	0.8259	0.7706	0.6634	0.3663	0.1
Gen. Inlet Temp., °F	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
Gearbox Loss, hp	870	870	870	870	870	870	870	870	870	870	870	870	870	870	870	870
Capacity Curve	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374	32374
Efficiency Curve	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376	32376
8th Stage Bleed																
HPC Stg8 Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IBH Bleed Flow, lb/s, lb/s	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HPC Stg8 Bld P, psi	86.312	81.903	80.834	79.439	78.053	76.615	75.192	73.751	72.288	70.77	69.249	67.592	65.961	64.443	62.587	61.139
HPC Stg8 Bld Temp., °F	533.62	518.53	514.86	510.24	505.37	500.18	495.28	490.32	485.17	479.73	474.14	467.9	461.75	456.67	450.47	445.43
CDP Bleed																
HPC CDP Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HPC CDP Bld P, psi	221.256	206.777	204.642	200.477	196.353	192.164	187.824	183.5	179.273	174.955	170.62	166.296	161.869	156.896	151.211	145.627
LPC Inlet Flow Wet, lb/s	228.553	228.58	228.589	228.598	228.604	228.61	228.616	228.622	228.628	228.633	228.64	228.645	228.65	228.657	228.669	228.671
LPC Inlet Flow Dry, lb/s	227.061	227.086	227.096	227.105	227.111	227.117	227.123	227.129	227.134	227.14	227.147	227.151	227.156	227.163	227.175	227.177
Comb. Air Flow, lb/s	116	110.2	110.1	108.3	106.6	105	103.2	101.4	99.6	97.8	96	94.2	92.3	90	87.4	84.8
LPC VBV Bld. Flow, lb/s	63.047	71.015	71.27	73.678	75.995	78.356	80.875	83.396	85.849	88.363	90.914	93.418	96.012	99.165	102.842	106.418
HPC Inlet Press., psi	25.624	25.544	25.485	25.442	25.436	25.434	25.432	25.433	25.44	25.442	25.434	25.459	25.48	25.462	25.384	25.43
T25 (HPC Inlet),, °F	186.109	186.8	186.625	186.812	187.184	187.751	188.359	188.975	189.588	190.205	190.802	191.525	192.302	193.179	193.961	195.021
HPC Inlet Temp., °F	197.143	196.756	196.509	196.319	196.274	196.246	196.217	196.201	196.205	196.192	196.138	196.213	196.273	196.18	195.849	196.013
Comp. Inlet SH, lbm/lbm	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Burner Mode	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Deck	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2	G0125P_V2
Card Pack	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp	8ka.scp
Ran Modified Input File	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Exhaust Card Pack	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp	7f5.scp
Other Options																
Inlet Config.	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial	Radial
Exhaust Config.	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial	Axial
Inlet Press. Loss Opt.	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed
Exh. Press. Loss Opt	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed
Generator																
Generator Name	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E	BDAX 7-290E
Coolant	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air
Run Control Level 1																
Target Power	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F	Shaft Horse F
Target Shaft Power, hp	17897.831	14318.265	14000	13000	12000	11000	10000	9000	8000	7000	6000	5000	4000	3000	2000	1000
Target Electr. Power, kW	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
Target Part Load, %	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Sprint ON/OFF	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off

Table N.3 - LM6000PG Tu

Case	**132**	**133**	**134**
Exh. Flow, ACFM	218761.8	218691	218691
Exh. Flow, SCFM	94347.8	94325.9	94325.9
Shaft Power, Gross, hp	500	490	490
Generator Information			
Gen. Capacity, kW	65477.5	65477.5	65477.5
Gen. Efficiency, %	0.1	0.1	0.1
Gen. Inlet Temp., °F	59	59	59
Gearbox Loss, hp	870	870	870
Capacity Curve	32374	32374	32374
Efficiency Curve	32376	32376	32376
8th Stage Bleed			
HPC Stg8 Bld Flow, lb/s	0	0	0
IBH Bleed Flow, lb/s, lb/s	N/A	N/A	N/A
HPC Stg8 Bld P, psi	60.566	60.558	60.558
HPC Stg8 Bld Temp., °F	443.43	443.4	443.4
CDP Bleed			
HPC CDP Bld Flow, lb/s	0	0	0
HPC CDP Bld P, psi	142.903	142.856	142.856
LPC Inlet Flow Wet, lb/s	228.667	228.667	228.667
LPC Inlet Flow Dry, lb/s	227.173	227.173	227.173
Comb. Air Flow, lb/s	83.6	83.6	83.6
LPC VBV Bld. Flow, lb/s	108.112	108.138	108.138
HPC Inlet Press., psi	25.507	25.511	25.511
T25 (HPC Inlet),, °F	195.651	195.667	195.667
HPC Inlet Temp., °F	196.306	196.323	196.323
Comp. Inlet SH, lbm/lbm	0.007	0.007	0.007
Burner Mode	None	None	None
Deck	**G0125P_V2**	**G0125P_V2**	**G0125P_V2 (PC, PD, PF, PH, PG)**
Card Pack	**8ka.scp**	**8ka.scp**	**8ka.scp**
Ran Modified Input File	**No**	**No**	**No**
Exhaust Card Pack	**7f5.scp**	**7f5.scp**	**7f5.scp**
Other Options			
Inlet Config.	**Radial**	**Radial**	**Radial**
Exhaust Config.	**Axial**	**Axial**	**Axial**
Inlet Press. Loss Opt.	Fixed	Fixed	Fixed
Exh. Press. Loss Opt	Fixed	Fixed	Fixed
Generator			
Generator Name	BDAX 7-290E	BDAX 7-290E	BDAX 7-290ERJT
Coolant	Air	Air	Air
Run Control Level 1			
Target Power	Shaft Horse P	Shaft Horse P	Shaft Horse Power
Target Shaft Power, hp	500	490	490
Target Electr. Power, kW	5000	5000	5000
Target Part Load, %	100	100	100
Sprint ON/OFF	Off	Off	Off

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**
Sprint Value	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Target PT Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
XNENG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Run Control Level 2																
P Level	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50
Cont. P Level	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
ZT25IC-HPC Inl T Add, °F	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PT Inlet Temp. Limit, °F																
CDC Temp. Limit, °F																
CDC Press. Limit, psi																
HPC Phys Speed Lim., rpm																
HPC Corr Speed Lim., rpm																
Av. Pgas @ B_plate, psi																
Operating Hours, hr																
Deterioration Levels																
HPC Stg8 Bld Flow, lb/h																
HPC CDP Bld Flow, lb/h																
Ambient Conditions																
Spec. Hum (Amb.), lbm/lbm	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Inlet Conditioning																
Type	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Spec. Hum (Amb.), lbm/lbm	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Evap Effectiveness, %	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill/Heat Option	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill/Heat Cap., kBTU/h	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill/Heat Temp., °F	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill Cap. RT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine Inlet																
Comp. Inlet SH, lbm/lbm	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Comp. Inlet Press., psia	13.955	13.958	13.979	13.982	13.974	13.946	13.922	13.899	13.876	13.854	13.852	13.852	13.852	13.851	13.851	13.851
Performance																
GTG Load, %	100	100	93.5886	88.5795	83.5666	78.5498	73.529	68.5044	63.4759	58.4435	53.4071	48.3669	43.3228	38.2747	33.2228	28.1669
Shaft Power, Gross, hp	76358.6	72597.5	68011.7	64432.2	60852.6	57273.1	53693.5	50113.9	46534.4	42954.8	39375.2	35795.7	32216.1	28636.5	25057	21477.4
Shaft HR, btu/(hp*h)	6320.752	6306.728	6311.272	6364.622	6442.027	6554.332	6645.525	6751.219	6872.43	7017.501	7189.129	7415.577	7702.411	8060.798	8532.583	9136.028
Shaft G-HR, btu/(hp*h)	6384.598	6370.433	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Gen. Output, Gross, kW	**55275**	**52515**	**49148**	**46518**	**43885**	**41251**	**38614**	**35975**	**33335**	**30692**	**28047**	**25400**	**22751**	**20100**	**17447**	**14792**
HR, btu/(kW*h)	**8732**	**8718**	**8734**	**8816**	**8933**	**9100**	**9241**	**9404**	**9594**	**9821**	**10093**	**10451**	**10907**	**11484**	**12254**	**13265**
Guar HR, btu/(kW*h)	**8820**	**8806**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**
STD Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPT Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOP Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gen. Output, Unit Net, kW	55274.5206	52515.4636	49148.473	46517.9417	43885.3935	41250.778	38614.114	35975.4113	33334.6571	30691.8613	28047.0108	25400.1129	22751.1632	20100.1601	17447.1051	14791.988
HR, Net, btu/(kW*h)	8731.764	8718.433	8733.546	8815.659	8932.682	9100.111	9240.701	9404.482	9593.743	9821.345	10092.825	10450.562	10906.765	11484.151	12254.218	13265.159
G-HR, Net, btu/(kW*h)	8819.964	8806.498	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Fuel Splits																
A Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
B Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inner Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
Sprint Value	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Target PT Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
XNENG	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Run Control Level 2																
P Level	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50	P50
Cont. P Level	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
ZT25IC-HPC Inl T Add, °F	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PT Inlet Temp. Limit, °F																
CDC Temp. Limit, °F																
CDC Press. Limit, psi																
HPC Phys Speed Lim., rpm																
HPC Corr Speed Lim., rpm																
Av. Pgas @ B_plate, psi																
Operating Hours, hr																
Deterioration Levels																
HPC Stg8 Bld Flow, lb/h																
HPC CDP Bld Flow, lb/h																
Ambient Conditions																
Spec. Hum (Amb.), lbm/lbm	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Inlet Conditioning																
Type	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Spec. Hum (Amb.), lbm/lbm	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Evap Effectiveness, %	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill/Heat Option	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill/Heat Cap., kBTU/h	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill/Heat Temp., °F	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Chill Cap. RT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Engine Inlet																
Comp. Inlet SH, lbm/lbm	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Comp. Inlet Press., psia	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.85	13.85	13.85	13.85
Performance																
GTG Load, %	23.1071	18.0434	20.8999	19.2184	17.5366	15.8544	14.1719	12.4889	10.8057	9.122	7.438	5.7536	4.0689	2.3838	0.6983	0.0219
Shaft Power, Gross, hp	17897.8	14318.3	14000	13000	12000	11000	10000	9000	8000	7000	6000	5000	4000	3000	2000	1000
Shaft HR, btu/(hp*h)	9958.211	11209.106	11063.878	11551.566	12118.052	12776.959	13563.339	14537.868	15769.028	17351.758	19450.808	22389.705	26793.849	34125.291	48561.238	91891.301
Shaft G-HR, btu/(hp*h)	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Gen. Output, Gross, kW	**12135**	**9476**	**9239**	**8496**	**7752**	**7009**	**6265**	**5521**	**4777**	**4032**	**3288**	**2543**	**1799**	**1054**	**309**	**10**
HR, btu/(kW*h)	**14688**	**16938**	**16765**	**17676**	**18758**	**20053**	**21650**	**23699**	**26410**	**30121**	**35494**	**44014**	**59585**	**97152**	**314629**	**9479103**
Guar HR, btu/(kW*h)	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**	**-999**
STD Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OPT Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOP Aux Load, kW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gen. Output, Unit Net, kW	12134.8175	9475.5861	9239.0508	8495.7394	7752.2671	7008.6339	6264.8397	5520.8846	4776.7688	4032.4912	3288.053	2543.4536	1798.6933	1053.7715	308.6885	9.6941
HR, Net, btu/(kW*h)	14687.52	16937.732	16765.173	17675.961	18757.948	20053.344	21649.938	23699.248	26409.533	30120.911	35493.603	44014.376	59585.147	97151.874	314629.374	9479103.23
G-HR, Net, btu/(kW*h)	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Fuel Splits																
A Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
B Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inner Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table N.3 - LM6000PG Tu

Case		**132**	**133**	**134**
Sprint Value	1	1	1	
Target PT Speed, rpm		3905	3905	3905
XNENG		1	1	1
Run Control Level 2				
P Level	P50	P50	P50	
Cont. P Level		50	50	50
ZT25IC-HPC Inl T Add, °F		0	0	0
PT Inlet Temp. Limit, °F				
CDC Temp. Limit, °F				
CDC Press. Limit, psi				
HPC Phys Speed Lim., rpm				
HPC Corr Speed Lim., rpm				
Av. Pgas @ B_plate, psi				
Operating Hours, hr				
Deterioration Levels				
HPC Stg8 Bld Flow, lb/h				
HPC CDP Bld Flow, lb/h				
Ambient Conditions				
Spec. Hum (Amb.), lbm/lbm		0.006	0.006	0.006
Inlet Conditioning				
Type	None	None	None	
Spec. Hum (Amb.), lbm/lbm		0.006	0.006	0.006
Evap Effectiveness, %	None	None	None	
Chill/Heat Option	None	None	None	
Chill/Heat Cap., kBTU/h	None	None	None	
Chill/Heat Temp., °F	None	None	None	
Chill Cap. RT		0	0	0
Engine Inlet				
Comp. Inlet SH, lbm/lbm		0.007	0.007	0.007
Comp. Inlet Press., psia		13.85	13.85	13.85
Performance				
GTG Load, %		-0.0624	-0.0641	-0.0641
Shaft Power, Gross, hp		500	490	490
Shaft HR, btu/(hp*h)		178585.379	182126.449	182126.449
Shaft G-HR, btu/(hp*h)		-999	-999	-999
Gen. Output, Gross, kW		**-28**	**-28**	**-28**
HR, btu/(kW*h)		**-3236310**	**-3149354**	**-3149354**
Guar HR, btu/(kW*h)		**-999**	**-999**	**-999**
STD Aux Load, kW		0	0	0
OPT Aux Load, kW		0	0	0
BOP Aux Load, kW		0	0	0
Gen. Output, Unit Net, kW		-27.5909	-28.3366	-28.3366
HR, Net, btu/(kW*h)		-3236309.8	-3149353.6	-3149353.6
G-HR, Net, btu/(kW*h)		-999	-999	-999
Fuel Splits				
A Ring, pph		0	0	0
B Ring, pph		0	0	0
C Ring, pph		0	0	0
Inner Ring, pph		0	0	0

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**
Outer Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inner Ring Pilot, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outer Ring Pilot, pph	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inner ELBO, pph	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Outer ELBO, pph	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Flows																
LPC Inlet Flow Dry, lb/h	1065711.6	1059271.2	1028289.6	1004706	974617.2	939970.8	914454	890672.4	861724.8	823676.4	816717.6	816822	816991.2	817135.2	817275.6	817362
LPC Inlet Flow Wet, lb/h	1072720.8	1066233.6	1035050.4	1011312	981025.2	946152	920466	896529.6	867391.2	829090.8	822085.2	822193.2	822362.4	822510	822650.4	822733.2
Exhaust Flow, lb/h	1114133.4	1100926.4	1065720.2	1037923.6	999108.7	942777.4	906744.6	874910.9	840016.8	797602.3	769319.3	742632.1	713843.3	685342.4	655317.4	626650.9
Engine Exhaust																
Exh Mol Wght, lb/lb-mol	27.899	27.993	28.041	28.069	28.084	28.083	28.104	28.127	28.149	28.167	28.198	28.229	28.259	28.289	28.32	28.355
Exh. Flow, SCFM	252568.5	248741.1	240371.3	233872.1	225004.6	212322.7	204060.1	196729	188735.2	179096.5	172554.8	166386.1	159763.8	153222.6	146351.8	139778
Exh. Flow, ACFM	657314.6	639557.5	610455.7	591350.3	570395.9	546554.1	525542.1	505655.2	485024.2	462948.3	443302.8	424640.1	405826.9	386876.7	367909.1	348403.8
Exh. Temp., °F	900.935	884.549	868.06	862.248	865.657	886.112	886.771	884.098	883.864	891.728	883.44	874.595	868.337	860.372	854.587	843.443
Exh. Pressure, psi	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785
Exh. Flow, lb/s	309.482	305.813	296.033	288.312	277.53	261.883	251.874	243.031	233.338	221.556	213.7	206.287	198.29	190.373	182.033	174.07
NOx Control																
NOx Target	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**	**NOx Level**
NOx Level, ppmvd	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**
Diluent Flow, lb/h	28955	30302	26994	25004	23303	21712	20001	18368	16800	15252	13697	12275	10889	9639	8410	7204
Diluent Temp., °F	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CDP Steam Temp., °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions (Estimated, NOT for Guarantee)																
NOx, Ref % O2, ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx (NO2), lb/h	48.51	45.98	43.12	41.17	39.39	37.7	35.82	33.97	32.1	30.25	28.42	26.62	24.89	23.15	21.44	19.7
CO, Ref % O2, ppmvd	29.5	67.2	43.4	34.3	34.2	34.8	34.6	34.2	34	33	32.4	31.8	30.2	30.3	29.2	28.4
CO, lb/h	34.87	75.2	45.53	34.42	32.75	31.91	30.22	28.31	26.61	24.31	22.44	20.66	18.32	17.06	15.24	13.58
CO2, lb/h	63669.64	60355.73	56650.57	54149.48	51767.01	49563.96	47118.24	44684.53	42244.44	39822.43	37407.27	35088.77	32812.73	30534.27	28292.19	25978.42
UHC Ref % O2, ppmvd	3	12	6	4	4	4	4	4	4	4	4	4	3	3	3	3
UHC (CH4), lb/h	2.21	7.74	3.38	2.22	2.11	2.06	1.95	1.82	1.71	1.56	1.44	1.32	1.16	1.08	0.97	0.86
SOx (SO2), lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Max Emissions																
NOx Ref 15% O2, ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx as NO2, lb/h	55.49	51.19	47.21	44.65	42.47	40.77	38.47	36.13	33.85	31.71	29.35	27.1	24.93	22.78	20.7	18.53
CO Ref 15% O2, ppmvd	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
CO, lb/h	127	117.15	108.05	102.2	97.19	93.31	88.05	82.7	77.47	72.57	67.18	62.02	57.05	52.14	47.37	42.41
HC Ref 15% O2, ppmvd	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
HC, lb/h	43.23	39.88	36.78	34.79	33.09	31.77	29.98	28.15	26.37	24.7	22.87	21.11	19.42	17.75	16.13	14.44
VOC Ref 15% O2, ppmvd	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
VOC, lb/h	8.49	7.83	7.22	6.83	6.5	6.24	5.89	5.53	5.18	4.85	4.49	4.15	3.82	3.49	3.17	2.84
Low Pressure Compressor																
LPC Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
LPC Corrected Speed, rpm	3899.7139	3899.4673	3899.6604	3899.7742	3899.874	3899.9817	3900.115	3900.2515	3900.3792	3900.4824	3900.6755	3900.8303	3901.0122	3901.1746	3901.3003	3901.4829
LPC Inlet Temp., °F	60.407	60.473	60.421	60.391	60.364	60.336	60.3	60.264	60.23	60.202	60.151	60.109	60.061	60.018	59.984	59.935
LPC Inlet Press., psi	13.955	13.958	13.979	13.982	13.974	13.946	13.922	13.899	13.876	13.854	13.852	13.852	13.852	13.851	13.851	13.851
LPC Inlet Flow Wet, lb/s	297.978	296.176	287.514	280.92	272.507	262.82	255.685	249.036	240.942	230.303	228.357	228.387	228.434	228.475	228.514	228.537
LPC Inlet Flow Dry, lb/s	296.031	294.242	285.636	279.085	270.727	261.103	254.015	247.409	239.368	228.799	226.866	226.895	226.942	226.982	227.021	227.045
LPC Disch. Temp., °F	235	255	248	246	240	223	217	214	210	203	201	201	200	199	198	197
LPC Disch. Press., psi	35	37	36	36	34	31	30	29	28	27	27	26	26	26	26	26

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
Outer Ring, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inner Ring Pilot, pph	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outer Ring Pilot, pph	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Inner ELBO, pph	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Outer ELBO, pph	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Flows																
LPC Inlet Flow Dry, lb/h	817419.6	817509.6	817545.6	817578	817599.6	817621.2	817642.8	817664.4	817682.4	817704	817729.2	817743.6	817761.6	817786.8	817830	817837.2
LPC Inlet Flow Wet, lb/h	822790.8	822888	822920.4	822952.8	822974.4	822996	823017.6	823039.2	823060.8	823078.8	823104	823122	823140	823165.2	823208.4	823215.6
Exhaust Flow, lb/h	598407.5	568066.7	561987.4	553188.6	544625.3	535982.4	526827.2	517613	508629.2	499370.4	490135.7	480992.8	471502.8	460044	446630	433616.4
Engine Exhaust																
Exh Mol Wght, lb/lb-mol	28.393	28.431	28.585	28.589	28.593	28.598	28.602	28.607	28.611	28.616	28.621	28.626	28.631	28.636	28.641	28.646
Exh. Flow, SCFM	133295.6	126368.3	124341.9	122378.2	120466.1	118535.4	116492.3	114437.1	112433.1	110368.8	108309.3	106270	104154.4	101607.2	98627.9	95736.6
Exh. Flow, ACFM	328321.6	307887.1	306586.7	300660.4	294740.1	288609.3	282261.1	276083.4	270132.4	264100.6	257972.3	251853.8	245608.4	238777.3	230697.4	222695.1
Exh. Temp., °F	828.051	814.102	829.392	824.76	819.454	813.248	807.083	801.61	796.419	791.341	785.548	779.343	773.161	768.919	763.201	756.435
Exh. Pressure, psi	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785	14.785
Exh. Flow, lb/s	166.224	157.796	156.108	153.664	151.285	148.884	146.341	143.781	141.286	138.714	136.149	133.609	130.973	127.79	124.064	120.449
NOx Control																
NOx Target	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level	NOx Level
NOx Level, ppmvd	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Diluent Flow, lb/h	6011	4916	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Diluent Temp., °F	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CDP Steam Temp., °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions (Estimated, NO																
NOx, Ref % O2, ppmvd	25	25	87	83.7	80.4	76.9	73.6	70.3	67.1	63.8	60.6	57.3	54	50.8	47.1	43.6
NOx (NO2), lb/h	17.86	16.07	53.99	50.34	46.78	43.28	39.94	36.8	33.85	31	28.26	25.63	23.13	20.75	18.27	15.97
CO, Ref % O2, ppmvd	27	25.8	5	5.3	5.9	6.8	7.7	8.8	10	11.4	13.1	15.8	19.2	23.2	29	36.3
CO, lb/h	11.73	10.11	1.89	1.96	2.1	2.32	2.54	2.79	3.06	3.38	3.74	4.31	5	5.78	6.84	8.09
CO2, lb/h	23612.09	21277.36	20556.45	19933.29	19306.2	18663.73	18015.35	17382.71	16763.76	16144.43	15516.21	14887.83	14256.92	13621.29	12924.75	12230.97
UHC Ref % O2, ppmvd	3	3	2	2	2	2	2	2	2	2	2	2	2	3	3	4
UHC (CH4), lb/h	0.74	0.63	0.44	0.43	0.42	0.4	0.39	0.37	0.36	0.35	0.33	0.32	0.31	0.36	0.43	0.52
SOx (SO2), lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Max Emissions																
NOx Ref 15% O2, ppmvd	25	25	87	83.7	80.4	76.9	73.6	70.3	67.1	63.8	60.6	57.3	54	50.8	47.1	43.6
NOx as NO2, lb/h	16.3	14.16	44.1	40.72	37.44	34.22	31.17	28.34	25.71	23.2	20.79	18.5	16.36	14.4	12.41	10.57
CO Ref 15% O2, ppmvd	94	94	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
CO, lb/h	37.31	32.42	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
HC Ref 15% O2, ppmvd	56	56	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
HC, lb/h	12.7	11.04	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
VOC Ref 15% O2, ppmvd	11	11	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
VOC, lb/h	2.5	2.17	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999	-999
Low Pressure Compressor																
LPC Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
LPC Corrected Speed, rpm	3901.7185	3901.9653	3902.0239	3902.0991	3902.175	3902.2527	3902.3279	3902.4028	3902.479	3902.5571	3902.6353	3902.72	3902.8022	3902.8748	3902.9626	3903.0305
LPC Inlet Temp., °F	59.873	59.807	59.791	59.771	59.751	59.731	59.711	59.691	59.67	59.65	59.629	59.606	59.584	59.565	59.542	59.524
LPC Inlet Press., psi	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.851	13.85	13.85	13.85	13.85
LPC Inlet Flow Wet, lb/s	228.553	228.58	228.589	228.598	228.604	228.61	228.616	228.622	228.628	228.633	228.64	228.645	228.65	228.657	228.669	228.671
LPC Inlet Flow Dry, lb/s	227.061	227.086	227.096	227.105	227.111	227.117	227.123	227.129	227.134	227.14	227.147	227.151	227.156	227.163	227.175	227.177
LPC Disch. Temp., °F	197	197	197	196	196	196	196	196	196	196	196	196	196	196	196	196
LPC Disch. Press., psi	26	26	25	25	25	25	25	25	25	25	25	25	25	25	25	25

Table N.3 - LM6000PG Tu

Case	132	133	134
Outer Ring, pph	0	0	0
Inner Ring Pilot, pph	0	0	0
Outer Ring Pilot, pph	N/A	N/A	N/A
Inner ELBO, pph	N/A	N/A	N/A
Outer ELBO, pph	N/A	N/A	N/A
Flows			
LPC Inlet Flow Dry, lb/h	817822.8	817822.8	817822.8
LPC Inlet Flow Wet, lb/h	823201.2	823201.2	823201.2
Exhaust Flow, lb/h	427368.6	427270.3	427270.3
Engine Exhaust			
Exh Mol Wght, lb/lb-mol	28.649	28.649	28.649
Exh. Flow, SCFM	94347.8	94325.9	94325.9
Exh. Flow, ACFM	218761.8	218691	218691
Exh. Temp., °F	752.539	752.429	752.429
Exh. Pressure, psi	14.785	14.785	14.785
Exh. Flow, lb/s	118.714	118.686	118.686
NOx Control			
NOx Target	**NOx Level**	**NOx Level**	**NOx Level**
NOx Level, ppmvd	**25**	**25**	**25**
Diluent Flow, lb/h	N/A	N/A	N/A
Diluent Temp., °F	N/A	N/A	N/A
CDP Steam Temp., °F	N/A	N/A	N/A
Emissions (Estimated, NO			
NOx, Ref % O2, ppmvd	41.8	41.8	41.8
NOx (NO2), lb/h	14.88	14.86	14.86
CO, Ref % O2, ppmvd	40.7	40.8	40.8
CO, lb/h	8.82	8.83	8.83
CO2, lb/h	11886.18	11879.45	11879.45
UHC Ref % O2, ppmvd	5	5	5
UHC (CH4), lb/h	0.6	0.61	0.61
SOx (SO2), lb/h	0	0	0
Max Emissions			
NOx Ref 15% O2, ppmvd	41.8	41.8	41.8
NOx as NO2, lb/h	9.71	9.69	9.69
CO Ref 15% O2, ppmvd	-999	-999	-999
CO, lb/h	-999	-999	-999
HC Ref 15% O2, ppmvd	-999	-999	-999
HC, lb/h	-999	-999	-999
VOC Ref 15% O2, ppmvd	-999	-999	-999
VOC, lb/h	-999	-999	-999
Low Pressure Compressor			
LPC Speed, rpm	3905	3905	3905
LPC Corrected Speed, rpm	3903.0569	3903.0574	3903.0574
LPC Inlet Temp., °F	59.517	59.517	59.517
LPC Inlet Press., psi	13.85	13.85	13.85
LPC Inlet Flow Wet, lb/s	228.667	228.667	228.667
LPC Inlet Flow Dry, lb/s	227.173	227.173	227.173
LPC Disch. Temp., °F	196	196	196
LPC Disch. Press., psi	26	26	26

Table N.3 - LM6000PG Turbine Detailed Run Data

Case	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**
LPC Disch. Flow, lb/s	294.544	292.087	283.581	276.645	266.542	251.505	242.185	234.011	224.97	213.831	206.611	199.786	192.357	184.974	177.158	169.718
LPC VBV Bld. Temp., °F	237.59	255.27	247.776	245.992	240.064	223.328	217.239	214.326	210.22	202.863	201.069	200.59	199.616	198.689	197.545	197.104
LPC VBV Bld. P, psi	34.69	36.605	35.982	35.547	34.194	31.194	30.039	29.319	28.407	26.888	26.54	26.431	26.2	25.978	25.697	25.598
LPC VBV Bld. Flow, lb/s	0	0	0	0.41	2.255	7.702	9.971	11.626	12.701	13.352	18.672	25.471	32.968	40.403	48.244	55.7
High Pressure Compressor																
HPC Shaft Speed, rpm	10764	10715	10611	10562	10511	10433	10375	10323	10271	10216	10133	10026	9926	9812	9683	9564
HPC Inlet Temp., °F	235.321	255.27	247.776	245.992	240.064	223.328	217.239	214.326	210.22	202.863	201.069	200.59	199.616	198.689	197.545	197.104
HPC Inlet Press., psi	34.69	36.605	35.982	35.547	34.194	31.194	30.039	29.319	28.407	26.888	26.54	26.431	26.2	25.978	25.697	25.598
HPC Inlet Flow, lb/s	294.544	292.087	283.581	276.645	266.542	251.505	242.185	234.011	224.97	213.831	206.611	199.786	192.357	184.974	177.158	169.718
HPC Disch. Temp., °F	1055.59	1080.6	1052.692	1039.079	1026.628	1012.14	997.455	983.515	969.207	955.025	937.622	920.801	904.321	886.416	868.333	848.223
HPC Disch. Press., psi	487.572	477.893	458.096	443.688	425.864	402.51	385.506	369.96	353.405	334.499	320.013	306.253	291.931	277.645	262.971	248.531
HPC Disch. Flow, lb/s	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HPC Stg8 Bld Temp., °F	657.592	690.536	670.483	660.344	651.908	643.894	633.501	623.21	612.56	602.339	591.279	583.351	574.945	566.247	558.658	547.732
HPC Stg8 Bld P, psi	147.498	150.639	144.709	140.171	134.864	128.675	123.544	118.643	113.373	107.494	103.695	101.191	98.074	95.397	93.38	90.36
HPC Stg8 Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HPC CDP Bld Temp., °F	1055.59	1080.6	1052.692	1039.079	1026.628	1012.14	997.455	983.515	969.207	955.025	937.622	920.801	904.321	886.416	868.333	848.223
HPC CDP Bld P, psi	463.37	453.528	434.58	420.796	403.912	382.034	365.883	351.058	335.303	317.396	303.535	290.352	276.656	262.99	248.968	235.137
HPC CDP Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Turbine																
PT Shaft Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
PT Inlet Temp. Limit, °F																
PT Inlet Press., psi	117.085	115.035	110.654	107.412	103.324	97.811	93.866	90.33	86.532	82.155	78.927	75.845	72.646	69.443	66.156	62.911
PT Inlet Flow, lb/h	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PT Discharge Temp., °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PT Disch P, psi	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PT Disch Flow, lb/h	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Composition, Mass %																
Fuel Bound N, %Mass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sulfur Content, %Mass	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Hydrogen, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methane, %	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482
Ethane, %	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458
Ethylene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propane, %	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507
Propylene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butane, %	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536
Butylene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butadiene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pentane, %	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617
Cyclopentane, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hexane, %	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483
Heptane, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CarbonMonoxide, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide, %	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863
Nitrogen, %	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919
Water Vapor, %	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Oxygen, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HydrogenSulfide, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ammonia, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table N.3 - LM6000PG Tu

Case	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131
LPC Disch. Flow, lb/s	162.394	154.452	154.197	151.799	149.468	147.115	144.62	142.107	139.657	137.129	134.61	132.115	129.524	126.384	122.703	119.135
LPC VBV Bld. Temp., °F	197.143	196.756	196.509	196.319	196.274	196.246	196.217	196.201	196.205	196.192	196.138	196.213	196.273	196.18	195.849	196.013
LPC VBV Bld. P, psi	25.624	25.544	25.485	25.442	25.436	25.434	25.432	25.433	25.44	25.442	25.434	25.459	25.48	25.462	25.384	25.43
LPC VBV Bld. Flow, lb/s	63.047	71.015	71.27	73.678	75.995	78.356	80.875	83.396	85.849	88.363	90.914	93.418	96.012	99.165	102.842	106.418
High Pressure Compresso																
HPC Shaft Speed, rpm	9456	9341	9335	9304	9271	9237	9201	9166	9131	9096	9059	9025	8988	8939	8885	8815
HPC Inlet Temp., °F	197.143	196.756	196.509	196.319	196.274	196.246	196.217	196.201	196.205	196.192	196.138	196.213	196.273	196.18	195.849	196.013
HPC Inlet Press., psi	25.624	25.544	25.485	25.442	25.436	25.434	25.432	25.433	25.44	25.442	25.434	25.459	25.48	25.462	25.384	25.43
HPC Inlet Flow, lb/s	162.394	154.452	154.197	151.799	149.468	147.115	144.62	142.107	139.657	137.129	134.61	132.115	129.524	126.384	122.703	119.135
HPC Disch. Temp., °F	826.399	803.318	799.525	792.792	785.739	778.343	771.043	763.714	756.329	748.599	740.649	732.355	723.913	715.483	705.687	695.781
HPC Disch. Press., psi	234.062	218.941	216.857	212.493	208.177	203.795	199.252	194.724	190.299	185.774	181.236	176.711	172.077	166.847	160.856	154.981
HPC Disch. Flow, lb/s	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HPC Stg8 Bld Temp., °F	533.624	518.527	514.863	510.243	505.37	500.175	495.277	490.319	485.173	479.731	474.143	467.902	461.754	456.674	450.47	445.434
HPC Stg8 Bld P, psi	86.312	81.903	80.834	79.439	78.053	76.615	75.192	73.751	72.288	70.77	69.249	67.592	65.961	64.443	62.587	61.139
HPC Stg8 Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HPC CDP Bld Temp., °F	826.399	803.318	799.525	792.792	785.739	778.343	771.043	763.714	756.329	748.599	740.649	732.355	723.913	715.483	705.687	695.781
HPC CDP Bld P, psi	221.256	206.777	204.642	200.477	196.353	192.164	187.824	183.5	179.273	174.955	170.62	166.296	161.869	156.896	151.211	145.627
HPC CDP Bld Flow, lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Turbine																
PT Shaft Speed, rpm	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905	3905
PT Inlet Temp. Limit, °F																
PT Inlet Press., psi	59.623	56.212	55.78	54.794	53.827	52.837	51.794	50.766	49.758	48.745	47.697	46.665	45.6	44.432	43.119	41.827
PT Inlet Flow, lb/h	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PT Discharge Temp., °F	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PT Disch P, psi	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PT Disch Flow, lb/h	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Composition, Mass %																
Fuel Bound N, %Mass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sulfur Content, %Mass	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Hydrogen, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methane, %	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482	79.6482
Ethane, %	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458	16.8458
Ethylene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propane, %	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507	1.507
Propylene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butane, %	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536	0.5536
Butylene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Butadiene, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pentane, %	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617	0.1617
Cyclopentane, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hexane, %	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483	0.0483
Heptane, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CarbonMonoxide, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide, %	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863	0.863
Nitrogen, %	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919	0.2919
Water Vapor, %	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Oxygen, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HydrogenSulfide, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ammonia, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table N.3 - LM6000PG Tu

Case	**132**	**133**	**134**
LPC Disch. Flow, lb/s	117.424	117.398	117.398
LPC VBV Bld. Temp., °F	196.306	196.323	196.323
LPC VBV Bld. P, psi	25.507	25.511	25.511
LPC VBV Bld. Flow, lb/s	108.112	108.138	108.138
High Pressure Compresso			
HPC Shaft Speed, rpm	8773	8772	8772
HPC Inlet Temp., °F	196.306	196.323	196.323
HPC Inlet Press., psi	25.507	25.511	25.511
HPC Inlet Flow, lb/s	117.424	117.398	117.398
HPC Disch. Temp., °F	690.717	690.616	690.616
HPC Disch. Press., psi	152.12	152.071	152.071
HPC Disch. Flow, lb/s	N/A	N/A	N/A
HPC Stg8 Bld Temp., °F	443.428	443.397	443.397
HPC Stg8 Bld P, psi	60.566	60.558	60.558
HPC Stg8 Bld Flow, lb/s	0	0	0
HPC CDP Bld Temp., °F	690.717	690.616	690.616
HPC CDP Bld P, psi	142.903	142.856	142.856
HPC CDP Bld Flow, lb/s	0	0	0
Power Turbine			
PT Shaft Speed, rpm	3905	3905	3905
PT Inlet Temp. Limit, °F			
PT Inlet Press., psi	41.202	41.192	41.192
PT Inlet Flow, lb/h	N/A	N/A	N/A
PT Discharge Temp., °F	N/A	N/A	N/A
PT Disch P, psi	N/A	N/A	N/A
PT Disch Flow, lb/h	N/A	N/A	N/A
Fuel Composition, Mass %			
Fuel Bound N, %Mass	0	0	0
Sulfur Content, %Mass	**0.1**	**0.1**	**0.1**
Hydrogen, %	0	0	0
Methane, %	79.6482	79.6482	79.6482
Ethane, %	16.8458	16.8458	16.8458
Ethylene, %	0	0	0
Propane, %	1.507	1.507	1.507
Propylene, %	0	0	0
Butane, %	0.5536	0.5536	0.5536
Butylene, %	0	0	0
Butadiene, %	0	0	0
Pentane, %	0.1617	0.1617	0.1617
Cyclopentane, %	0	0	0
Hexane, %	0.0483	0.0483	0.0483
Heptane, %	0	0	0
CarbonMonoxide, %	0	0	0
Carbon Dioxide, %	0.863	0.863	0.863
Nitrogen, %	0.2919	0.2919	0.2919
Water Vapor, %	0.002	0.002	0.002
Oxygen, %	0	0	0
HydrogenSulfide, %	0	0	0
Ammonia, %	0	0	0

Table N.4 - SGT-800 Turbine Potential Emissions Summary

DIMENSIONAL ANALYSIS

Mass Conversion	0.4536	kg/lb	*NIST SP1038*
Mass Conversion	2,000	lb/ton	*NIST SP1038*
Time Conversion	24	hr/day	
Molecular Weight of Exhaust	28.7	lb/lbmol	*Vendor Guarantee*
Molecular Weight of HCl	36.5	lb/lbmol	
Molecular Weight of SO_2	64	lb/lbmol	
Molecular Weight of NH_3	17	lb/lbmol	
Molecular Weight of Sulfur	32	lb/lbmol	
Molecular Weight of NO_2	46	lb/lbmol	
Molecular Weight of VOC	16	lb/lbmol (as carbon)	
Molecular Weight of CO	28	lb/lbmol	
Molecular Weight of CH_2O	30	lb/lbmol	
Molecular Weight of CO_2	44	lb/lbmol	
Molar Volume @STP	385.2	scf/lbmol	
GWP - CO_2	1	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - CH_4	25	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - N_2O	298	GWP	*40 CFR 98 Subpart A, Table A-1*

OPERATING PARAMETERS

Fuel Used	Natural Gas or C2		
Maximum Heat Input	496.2	MMBtu/hr	
Steady State Operating Hours	8,248	hrs/yr	*= 8,760 (hr/yr) - Startup Hours (hr/yr) - Shutdown Hours (hr/yr)*
Startup Hours	256	hrs/yr	*Engineering Estimate*
Shutdown Hours	256	hrs/yr	*Engineering Estimate*

UNCONTROLLED SGT-800 EMISSION GUARANTEES

VOC	5.0	ppmvd at 15% O2	
NO_X	35.0	ppmvd at 15% O2	
$PM/PM_{10}/PM_{2.5}$	2.5	lb/hr at 15% O2	
CO	5.0	ppmvd at 15% O2	
Formaldehyde	1.0	ppmvd at 15% O2	

CONTROLLED SGT-800 EMISSION GUARANTEES

VOC	0.5	ppmvd at 15% O2	
NO_X	1.75	ppmvd at 15% O2	*With SCR*
CO	0.5	ppmvd at 15% O2	*With CatOx*
Formaldehyde	0.1	ppmvd at 15% O2	

SUSD EMISSION GUARANTEES	*lb/startup*	*lb/shutdown*
VOC	1.2	0.2
NO_X	10.70	8.7
$PM/PM_{10}/PM_{2.5}$	0.30	0.2
CO	21.6	5.2

SGT-800 OPERATING PARAMETERS

Temperature Range (deg F)	Heat Input Rate (MMBtu/hr)	Fuel Usage (lb/hr)	Fuel Usage (scf/hr)	Exhaust Flow (scfm)	Exhaust Flow (acfm)	Exhaust Temp (deg F)	Moisture Content (%)	Oxygen Content (%)
0	496.2	24,289.2	365,684	261,856	710,699	972	6.02	13.37

POTENTIAL EMISSIONS

Pollutant	Emission Factor Value	Emission Factor Units	Emission Factor Notes	Emission Rates (lb/hr) Steady State	Startup	Shutdown	Maximum Short Term Emissions (lb/hr)	Maximum Annual Emissions (tpy)
PM [a,b]	2.50	lb/hr at 15% O2	Vendor Guarantee	3.52	0.72	0.48	3.52	14.86
PM_{10} [a,b]	2.50	lb/hr at 15% O2	Vendor Guarantee	3.52	0.72	0.48	3.52	14.86
$PM_{2.5}$ [a,b]	2.50	lb/hr at 15% O2	Vendor Guarantee	3.52	0.72	0.48	3.52	14.86
SO_2 [c]	3.40E-03	lb/MMBtu	AP-42 Table 3.1-2a		1.69		1.69	7.39
VOC [a,b]	0.5	ppmvd at 15% O2	Vendor Guarantee	0.35	2.88	0.48	2.88	1.86
NO_X [a,b]	1.75	ppmvd at 15% O2	Vendor Guarantee	3.49	25.68	20.88	25.68	20.35
CO [a,b]	0.5	ppmvd at 15% O2	Vendor Guarantee	0.61	51.84	12.48	51.84	10.74
Ammonia [d]	5.0	ppmvd	Assumed Ammonia Slip	3.26	-	3.26	3.26	14.27
Sulfuric Acid Mist	1.70E-04	lb/MMBtu	5% of SO_2		0.08		0.08	0.37
HAP								
Acetaldehyde	4.00E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.02		0.02	0.09
Acrolein	6.40E-06	lb/MMBtu	AP-42 Table 3.1-3.		0.00		0.00	0.01
Benzene	1.20E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.01		0.01	0.03
1,3-Butadiene	4.30E-07	lb/MMBtu	AP-42 Table 3.1-3.		0.00		0.00	0.00
Ethylbenzene	3.20E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.02		0.02	0.07
Formaldehyde [a,b]	0.1	ppmvd at 15% O2	Vendor Guarantee		0.13		0.13	0.57
Naphthalene	1.30E-06	lb/MMBtu	AP-42 Table 3.1-3.		0.00		0.00	0.00
Proplylene Oxide	2.90E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.01		0.01	0.06
Toluene	1.30E-04	lb/MMBtu	AP-42 Table 3.1-3.		0.06		0.06	0.28
o-Xylene	6.40E-05	lb/MMBtu	AP-42 Table 3.1-3.		0.03		0.03	0.14
Total HAPs [c]					0.29		0.29	1.25
Greenhouse Gases								
CO_2 [e]	6.12	wt% in Exhaust	Vendor Guarantee		71,581.97		71,581.97	313,529
CH_4 [f]	1.00E-03	kg/MMBtu	40 CFR 98, Table C-2 for NG		1.09		1.09	4.79
N_2O [f]	1.00E-04	kg/MMBtu	40 CFR 98, Table C-2 for NG		0.11		0.11	0.48
CO_2e [g]	-	-	-		-		-	313,792

[a] *Emissions (lb/hr) = Guarantee (ppmvd) x [20.9 x (1 - Moisture Content / 100) - Oxygen Content] / [20.9 - 15] x 1 (atm) x Exhaust Flow Rate (acfm) x Molecular Weight (lb/lbmol) x 60 (min/hr) / [0.730241312 x (Exhaust Temperature (F) + 460) x 1,000,000]*
PM Emissions also include additional PM from SCR/OxCat (lb/hr)
Based on operation at 100% load, 50% relative humidity, 20.9% O2 in air, and 1 atm pressure. Assumes the exhaust behaves as an ideal gas, with universal gas constant, R, of 0.730241312 ft ^{3} -atm/°R/lbmol.
Conversion from Temp (F) to Temp (Rankine) = Temp (F) + 460

[b] *Annual startup and shutdown emissions are calculated using a duration of 25 minutes for each startup or shutdown event.*

[c] *SO_2 or non-CH_2O HAPs Emissions (lb/hr) = Maximum Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)*
SO_2 or non-CH_2O HAPs Emissions (tpy) = Maximum Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8,760 (hr/yr) / 2,000 (lb/ton)

[d] *Ammonia Emissions (lb/hr) = Ammonia (ppmvd) x Exhaust Flow Rate (scfm) x Molecular Weight of Ammonia (lb/lbmol) x 60 (min/hr) x (1 - Moisture%) / [Molar Volume @ STP (lbmol/scf) x 1,000,000]*

[e] *CO_2 Emission Rate (lb/hr) = CO2 wt% in Exhaust x Exhaust Flow Rate (scfm) x 60 (min/hr) x Molecular Weight of Exhaust (lb/lbmol) / Ideal molar volume (scf/lbmol)*
CO_2 Emission Rate (tpy) = CO_2 Emission Rate (lb/hr) × 8,760 (hr/yr) / 2,000 (lb/ton)

[f] *GHG Emission Rate (lb/hr) = Heat Input (MMBtu/hr) × Emission Factor (kg/MMBtu) / 0.45359237 (kg/lb)*
GHG Emission Rate (tpy) = Heat Input (MMBtu/hr) × Emission Factor (kg/MMBtu) × 8,760 (hr/yr) / 0.45359237 (kg/lb) / 2,000 (lb/ton)

[g] *CO_2e Emissions (tpy) = Annual CO_2 Emission (tpy) x CO_2 GWP + Annual CH_4 Emissions (tpy) x CH_4 GWP + Annual N_2O Emissions (tpy) x N_2O GWP*

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity		1	2	3	4	5	6	7	8	9	10	11	12	13	14
Ambient temp.	F	0	0	0	10	10	10	20	20	20	30	30	30	40	40
Relative humidity	%	50	60	68	50	60	68	50	60	68	50	60	68	50	60
Load	%	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Turbine speed	rpm	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600
Power output	kW	57854	57859	57863	56484	56492	56498	55122	55133	55143	53828	53846	53860	52510	52536
Efficiency	%	39.79	39.79	39.79	39.69	39.69	39.69	39.57	39.57	39.57	39.45	39.45	39.45	39.32	39.32
Heat Rate	Btu/kWh	8576	8576	8576	8597	8597	8597	8623	8623	8623	8648	8648	8648	8677	8677
Fuel flow	lb/s	6.746	6.747	6.747	6.603	6.604	6.605	6.463	6.465	6.466	6.33	6.332	6.334	6.195	6.198
Exhaust flow	lb/s	324.9	324.9	324.8	320	320	320	315.2	315.2	315.1	310.5	310.5	310.5	306	306
Exhaust temp.	F	972	972	972	976	976	976	980	980	980	984	985	985	988	988
Heat cont. Ref. T	F	212	212	212	212	212	212	212	212	212	212	212	212	212	212
Exhaust heat cont.	MBtu/h	231.4	231.4	231.4	229.2	229.2	229.2	227.1	227.2	227.2	225.2	225.2	225.3	223.1	223.2
Inlet Cooler	---	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
Air after cooler	°F	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temp. GT_inlet	°F	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Water flow	lb/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chill. P. / Evap eff	kJ/s / %	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Actual inlet loss	Inch H2O	4.3	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.2	4.2	4.2	4.1	4.1
Actual outlet loss	Inch H2O	13.1	13.1	13.1	12.8	12.8	12.8	12.5	12.5	12.5	12.1	12.1	12.1	11.8	11.8
Compressor inlet air	lb/s	318.2	318.2	318.2	313.5	313.5	313.5	308.8	308.8	308.8	304.3	304.3	304.2	299.9	299.9
Compr. discharge temp	F	768	767.9	767.9	781.1	781	780.9	794.1	794	793.9	806.9	806.7	806.6	819.4	819.2
Compr. discharge press.	psia	340.4	340.4	340.4	335.5	335.5	335.5	330.6	330.6	330.6	326	326	326	321.4	321.4
Load stress factor, Cx	EOH/H	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SO2	% WT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H2O	% WT	3.78	3.79	3.8	3.79	3.8	3.81	3.8	3.83	3.85	3.84	3.88	3.91	3.9	3.95
CO2	% WT	6.12	6.12	6.12	6.08	6.08	6.09	6.05	6.05	6.05	6.01	6.01	6.01	5.97	5.97
N2	% WT	73.93	73.92	73.91	73.92	73.9	73.89	73.89	73.88	73.86	73.86	73.83	73.81	73.81	73.77
O2	% WT	14.91	14.91	14.91	14.96	14.96	14.95	15	14.99	14.99	15.04	15.02	15.02	15.07	15.05
Ar	% WT	1.26	1.26	1.26	1.26	1.26	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
SO2	% VOL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H2O	% VOL	6.02	6.04	6.05	6.03	6.05	6.07	6.05	6.09	6.12	6.11	6.17	6.21	6.2	6.29
CO2	% VOL	3.99	3.99	3.99	3.97	3.97	3.97	3.94	3.94	3.94	3.92	3.92	3.92	3.89	3.89
N2	% VOL	75.71	75.7	75.69	75.69	75.67	75.66	75.66	75.63	75.61	75.6	75.55	75.52	75.51	75.44
O2	% VOL	13.37	13.37	13.37	13.41	13.41	13.4	13.45	13.44	13.43	13.47	13.46	13.45	13.5	13.48
Ar	% VOL	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity		15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Ambient temp.	F	40	50	50	50	59	59	59	70	70	70	80	80	80	90	90
Relative humidity	%	68	50	60	68	50	60	68	50	60	68	50	60	68	50	60
Load	%	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Turbine speed	rpm	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600	6600
Power output	kW	52556	51233	51270	51299	51275	51084	50938	50007	49583	49266	48324	47854	47503	46705	46197
Efficiency	%	39.32	39.19	39.19	39.19	39.18	39.16	39.14	39	38.92	38.86	38.69	38.59	38.51	38.33	38.21
Heat Rate	Btu/kWh	8677	8707	8707	8706	8709	8714	8718	8748	8766	8780	8819	8842	8861	8901	8930
Fuel flow	lb/s	6.201	6.065	6.07	6.073	6.072	6.053	6.039	5.949	5.91	5.881	5.795	5.754	5.723	5.653	5.61
Exhaust flow	lb/s	305.9	301.6	301.5	301.4	300.8	300	299.4	295.8	294.1	292.7	289	287	285.4	282.3	280
Exhaust temp.	F	988	992	992	992	993	994	995	998	1000	1001	1005	1007	1009	1012	1015
Heat cont. Ref. T	F	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212
Exhaust heat cont.	MBtu/h	223.3	221.2	221.3	221.5	221.8	221.5	221.4	220	219.4	219	217.5	216.9	216.5	215.4	214.9
Inlet Cooler	---	Off	Off	Off	Off	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.
Air after cooler	°F	0	0	0	0	50.6	52.4	53.7	59.9	62.1	63.7	68.3	70.9	72.8	76.8	79.7
Temp. GT_inlet	°F	0	0	0	0	50.9	52.6	53.9	60.2	62.3	63.9	68.7	71.2	73.1	77.2	80.1
Water flow	lb/s	0	0	0	0	0.6	0.47	0.38	0.72	0.56	0.44	0.82	0.64	0.5	0.92	0.71
Chill. P. / Evap eff	kJ/s / %	0	0	0	0	88	88	88	88	88	88	88	88	88	88	88
Actual inlet loss	Inch H2O	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4	4	4	3.9	3.9	3.9	3.8
Actual outlet loss	Inch H2O	11.8	11.5	11.5	11.5	11.5	11.4	11.4	11.2	11	10.9	10.7	10.6	10.5	10.3	10.1
Compressor inlet air	lb/s	299.8	295.7	295.6	295.5	294.8	294	293.4	290	288.3	286.9	283.3	281.3	279.8	276.7	274.5
Compr. discharge temp	F	819	831.7	831.3	831	831.1	833	834.4	841.9	844.3	846.1	851.7	854.2	856.1	860.7	863.4
Compr. discharge press.	psia	321.3	316.9	316.9	316.9	316.4	315.6	315.1	311.5	309.8	308.5	304.8	302.8	301.4	298.3	296.1
Load stress factor, Cx	EOH/H	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SO2	% WT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H2O	% WT	4	4	4.08	4.14	4.36	4.42	4.47	4.63	4.74	4.82	4.97	5.13	5.26	5.42	5.65
CO2	% WT	5.98	5.93	5.94	5.94	5.95	5.95	5.95	5.93	5.93	5.92	5.91	5.91	5.91	5.9	5.91
N2	% WT	73.73	73.72	73.67	73.62	73.46	73.41	73.37	73.24	73.17	73.1	72.98	72.87	72.77	72.64	72.47
O2	% WT	15.04	15.1	15.07	15.05	14.99	14.98	14.97	14.95	14.93	14.91	14.89	14.86	14.83	14.8	14.74
Ar	% WT	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.24	1.24	1.24	1.24	1.24	1.24	1.23	1.23
SO2	% VOL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H2O	% VOL	6.36	6.35	6.48	6.58	6.91	7.01	7.09	7.34	7.49	7.62	7.86	8.1	8.3	8.54	8.9
CO2	% VOL	3.89	3.86	3.86	3.86	3.87	3.86	3.86	3.84	3.84	3.84	3.82	3.82	3.82	3.81	3.81
N2	% VOL	75.39	75.38	75.28	75.21	74.95	74.87	74.81	74.6	74.47	74.37	74.18	73.99	73.84	73.64	73.36
O2	% VOL	13.46	13.51	13.48	13.46	13.39	13.37	13.36	13.33	13.3	13.28	13.25	13.21	13.17	13.13	13.06
Ar	% VOL	0.9	0.9	0.9	0.9	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.88	0.87

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity		30	31	32	33	34	35	36
Ambient temp.	F	90	100	100	100	104	104	104
Relative humidity	%	68	50	60	68	50	60	68
Load	%	100	100	100	100	100	100	100
Turbine speed	rpm	6600	6600	6600	6600	6600	6600	6600
Power output	kW	45827	45185	44526	44001	44471	43741	43227
Efficiency	%	38.12	37.97	37.79	37.63	37.78	37.57	37.42
Heat Rate	Btu/kWh	8952	8987	9030	9067	9032	9083	9120
Fuel flow	lb/s	5.578	5.522	5.467	5.425	5.462	5.402	5.36
Exhaust flow	lb/s	278.2	275.6	272.5	270	272.4	268.9	266.3
Exhaust temp.	F	1018	1021	1025	1028	1025	1030	1033
Heat cont. Ref. T	F	212	212	212	212	212	212	212
Exhaust heat cont.	MBtu/h	214.6	213.8	213.1	212.6	212.9	212.2	211.7
Inlet Cooler	---	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.	Evap.
Air after cooler	°F	81.9	85.3	88.6	91.1	88.7	92.2	94.8
Temp. GT_inlet	°F	82.2	85.8	89	91.4	89.2	92.6	95.1
Water flow	lb/s	0.56	1.02	0.79	0.61	1.05	0.81	0.63
Chill. P. / Evap eff	kJ/s / %	88	88	88	88	88	88	88
Actual inlet loss	Inch H2O	3.8		3.7	3.6	3.7	3.6	3.5
Actual outlet loss	Inch H2O	10	9.9	9.7	9.5	9.7	9.5	9.3
Compressor inlet air	lb/s	272.7	270.2	267.1	264.6	267.1	263.6	261
Compr. discharge temp	F	865.2	869	871.7	873.6	872.2	874.8	876.6
Compr. discharge press.	psia	294.5	292	289	286.7	289	285.7	283.2
Load stress factor, Cx	EOH/H	1	1	1	1	1	1	1
SO2	% WT	0	0	0	0	0	0	0
H2O	% WT	5.85	6.01	6.35	6.62	6.29	6.68	7
CO2	% WT	5.91	5.91	5.92	5.92	5.91	5.92	5.93
N2	% WT	72.32	72.2	71.95	71.74	71.99	71.7	71.46
O2	% WT	14.69	14.66	14.57	14.49	14.59	14.48	14.4
Ar	% WT	1.23	1.23	1.22	1.22	1.22	1.22	1.21
SO2	% VOL	0	0	0	0	0	0	0
H2O	% VOL	9.19	9.44	9.95	10.37	9.86	10.45	10.93
CO2	% VOL	3.8	3.8	3.8	3.8	3.79	3.79	3.79
N2	% VOL	73.13	72.93	72.53	72.2	72.6	72.14	71.76
O2	% VOL	13	12.96	12.86	12.77	12.88	12.76	12.66
Ar	% VOL	0.87	0.87	0.86	0.86	0.86	0.86	0.85

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	1	2	3	4	5	6	7	8	9	10	11	12	13	14
TURBINE EXAUST MOL. WEIGHT LBS/MOLE	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.6
NOX EMISSIONS PPMD @ 15 % O2	35	35	35	35	35	35	35	35	35	35	35	35	35	35
CO EMISSIONS PPMD @ 15 % O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
VOC EMISSIONS PPMD @ 15 % O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CH2O EMISSIONS PPMD @ 15 % O2	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PARTICULATE EMISSIONS LBS/HR @ 15 % O2 DRY	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
MASS FLOW RATE LBS/SEC	324.9	324.9	324.8	320	320	320	315.2	315.2	315.1	310.5	310.5	310.5	306	306
MASS FLOW RATE LBS/HR	1,169,640	1,169,640	1,169,280	1,152,000	1,152,000	1,152,000	1,134,720	1,134,720	1,134,360	1,117,800	1,117,800	1,117,800	1,101,600	1,101,600
MOLES FLOW RATE MOLES/HR	40,788	40,786	40,775	40,172	40,175	40,178	39,577	39,583	39,575	38,998	39,007	39,013	38,450	38,463
DRY MOLES /HR	38,332	38,323	38,308	37,750	37,744	37,739	37,182	37,172	37,153	36,615	36,600	36,590	36,066	36,044
O2 CONCENTRATION % DRY BASIS	14.2%	14.2%	14.2%	14.3%	14.3%	14.3%	14.3%	14.3%	14.3%	14.3%	14.3%	14.3%	14.4%	14.4%
ACTUAL NOX CONCENTRATION PPM DRY	39.6	39.6	39.6	39.3	39.3	39.4	39.1	39.1	39.1	38.9	38.9	38.9	38.6	38.6
ACTUAL CO CONCENTRATION PPM DRY	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.5	5.5
ACTUAL VOC CONCENTRATION PPM DRY	5.7	5.7	5.7	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.5	5.5
ACTUAL CH2O CONCENTRATION PPM DRY	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
NOX MOLES PER HOUR	1.52	1.52	1.52	1.48	1.48	1.49	1.45	1.45	1.45	1.42	1.42	1.42	1.39	1.39
CO MOLES PER HOUR	0.22	0.22	0.22	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
VOC MOLES PER HOUR	0.22	0.22	0.22	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
CH2O MOLES PER HOUR	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
NOX AS NO2 MOLECULAR WEIGHT	46	46	46	46	46	46	46	46	46	46	46	46	46	46
CO MOLECULAR WEIGHT	28	28	28	28	28	28	28	28	28	28	28	28	28	28
VOC (as CH4) MOLECULAR WEIGHT	16	16	16	16	16	16	16	16	16	16	16	16	16	16
CH2O MOLECULAR WEIGHT	30	30	30	30	30	30	30	30	30	30	30	30	30	30
NOX EMISSIONS LBS/HOUR	69.8	69.8	69.7	68.3	68.3	68.3	66.8	66.8	66.9	65.5	65.5	65.5	64.0	64.1
CO EMISSIONS LBS/HOUR	6.1	6.1	6.1	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.9	5.9
VOC EMISSIONS LBS/HOUR	3.47	3.5	3.5	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
CH2O EMISSIONS LBS/HOUR	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
PARTICULATE EMISSIONS LBS/HR	2.83	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
OPERATING HOURS PER YEAR	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248
RAW NOX EMISSIONS TONS/YEAR	287.9	287.7	287.5	281.6	281.5	281.8	275.5	275.6	275.7	270.0	270.0	270.1	264.1	264.3
RAW CO EMISSIONS TONS/YEAR	25.0	25.0	25.0	24.9	24.9	24.9	24.7	24.7	24.7	24.6	24.6	24.6	24.4	24.4
RAW VOC EMISSIONS TONS/YEAR	14.3	14.3	14.3	14.2	14.2	14.2	14.1	14.1	14.1	14.0	14.1	14.1	13.9	14.0
RAW CH2O EMISSIONS TONS/YEAR	5.4	5.4	5.4	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.2	5.2
PARTICULATE EMISSIONS TONS/YEAR	11.7	11.7	11.7	11.6	11.6	11.6	11.5	11.5	11.5	11.5	11.5	11.5	11.4	11.4
NOX SCR REDUCTION %	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
CO CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
VOC CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CH2O CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
NOX EMISSIONS AFTER CATALYST TONS/YEAR	14.394	14.4	14.4	14.1	14.1	14.1	13.8	13.8	13.8	13.5	13.5	13.5	13.2	13.2
CO EMISSIONS AFTER CATALYST TONS/YEAR	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.4	2.4
VOC EMISSIONS AFTER CATALYST TONS/YEAR	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CH2O EMISSIONS AFTER CATALYST TONS/YEAR	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Ammonia injection Requirements lbsd/hr as (100% NH3)	**34.3**	**34.3**	**34.3**	**33.8**	**33.8**	**33.8**	**33.2**	**33.2**	**33.2**	**32.7**	**32.7**	**32.7**	**32.3**	**32.3**

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
TURBINE EXAUST MOL. WEIGHT LBS/MOLE	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.5	28.5	28.5	28.5	28.4	28.4	28.4	28.3
NOX EMISSIONS PPMD @ 15 % O2	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
CO EMISSIONS PPMD @ 15 % O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
VOC EMISSIONS PPMD @ 15 % O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CH2O EMISSIONS PPMD @ 15 % O2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PARTICULATE EMISSIONS LBS/HR @ 15 % O2 DRY	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
MASS FLOW RATE LBS/SEC	305.9	301.6	301.5	301.4	300.8	300	299.4	295.8	294.1	292.7	289	287	285.4	282.3	280
MASS FLOW RATE LBS/HR	1,101,240	1,085,760	1,085,400	1,085,040	1,082,880	1,080,000	1,077,840	1,064,880	1,058,760	1,053,720	1,040,400	1,033,200	1,027,440	1,016,280	1,008,000
MOLES FLOW RATE MOLES/HR	38,461	37,923	37,929	37,927	37,898	37,818	37,749	37,337	37,148	36,985	36,559	36,335	36,157	35,802	35,560
DRY MOLES /HR	36,015	35,514	35,471	35,431	35,279	35,167	35,073	34,597	34,365	34,167	33,686	33,392	33,156	32,744	32,395
O2 CONCENTRATION % DRY BASIS	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.3%
ACTUAL NOX CONCENTRATION PPM DRY	38.7	38.4	38.5	38.5	38.7	38.7	38.7	38.6	38.7	38.7	38.7	38.7	38.8	38.8	38.9
ACTUAL CO CONCENTRATION PPM DRY	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.6
ACTUAL VOC CONCENTRATION PPM DRY	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.6
ACTUAL CH2O CONCENTRATION PPM DRY	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
NOX MOLES PER HOUR	1.39	1.36	1.36	1.36	1.36	1.36	1.36	1.34	1.33	1.32	1.30	1.29	1.29	1.27	1.26
CO MOLES PER HOUR	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
VOC MOLES PER HOUR	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
CH2O MOLES PER HOUR	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
NOX AS NO2 MOLECULAR WEIGHT	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
CO MOLECULAR WEIGHT	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
VOC (as CH4) MOLECULAR WEIGHT	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
CH2O MOLECULAR WEIGHT	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
NOX EMISSIONS LBS/HOUR	64.1	62.7	62.8	62.8	62.7	62.6	62.4	61.5	61.2	60.8	59.9	59.5	59.2	58.5	58.0
CO EMISSIONS LBS/HOUR	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	6.0	6.0
VOC EMISSIONS LBS/HOUR	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
CH2O EMISSIONS LBS/HOUR	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
PARTICULATE EMISSIONS LBS/HR	2.8	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
OPERATING HOURS PER YEAR	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248	8248
RAW NOX EMISSIONS TONS/YEAR	264.5	258.7	258.9	258.9	258.7	258.1	257.4	253.6	252.3	250.9	247.2	245.2	243.9	241.1	239.3
RAW CO EMISSIONS TONS/YEAR	24.5	24.3	24.3	24.4	24.4	24.5	24.5	24.4	24.5	24.5	24.5	24.5	24.5	24.5	24.6
RAW VOC EMISSIONS TONS/YEAR	14.0	13.9	13.9	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.1
RAW CH2O EMISSIONS TONS/YEAR	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.3
PARTICULATE EMISSIONS TONS/YEAR	11.4	11.3	11.3	11.3	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.5
NOX SCR REDUCTION %	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
CO CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
VOC CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CH2O CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
NOX EMISSIONS AFTER CATALYST TONS/YEAR	13.2	12.9	12.9	12.9	12.9	12.9	12.9	12.7	12.6	12.5	12.4	12.3	12.2	12.1	12.0
CO EMISSIONS AFTER CATALYST TONS/YEAR	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
VOC EMISSIONS AFTER CATALYST TONS/YEAR	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CH2O EMISSIONS AFTER CATALYST TONS/YEAR	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Ammonia injection Requirements lbsd/hr as (100% NH3)	**32.3**	**31.8**	**31.8**	**31.8**	**31.7**	**31.6**	**31.6**	**31.2**	**31.0**	**30.9**	**30.5**	**30.3**	**30.1**	**29.8**	**29.5**

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	30	31	32	33	34	35	36
TURBINE EXAUST MOL. WEIGHT LBS/MOLE	28.3	28.3	28.2	28.2	28.2	28.2	28.1
NOX EMISSIONS PPMD @ 15 % O2	35	35	35	35	35	35	35
CO EMISSIONS PPMD @ 15 % O2	5	5	5	5	5	5	5
VOC EMISSIONS PPMD @ 15 % O2	5	5	5	5	5	5	5
CH2O EMISSIONS PPMD @ 15 % O2	1	1	1	1	1	1	1
PARTICULATE EMISSIONS LBS/HR @ 15 % O2 DRY	2.5	2.5	2.5	2.5	2.5	2.5	2.5
MASS FLOW RATE LBS/SEC	278.2	275.6	272.5	270	272.4	268.9	266.3
MASS FLOW RATE LBS/HR	1,001,520	992,160	981,000	972,000	980,640	968,040	958,680
MOLES FLOW RATE MOLES/HR	35,376	35,075	34,750	34,486	34,730	34,358	34,094
DRY MOLES /HR	32,125	31,764	31,292	30,910	31,306	30,768	30,367
O2 CONCENTRATION % DRY BASIS	14.3%	14.3%	14.3%	14.2%	14.3%	14.2%	14.2%
ACTUAL NOX CONCENTRATION PPM DRY	39.1	39.1	39.3	39.5	39.2	39.5	39.7
ACTUAL CO CONCENTRATION PPM DRY	5.6	5.6	5.6	5.6	5.6	5.6	5.7
ACTUAL VOC CONCENTRATION PPM DRY	5.6	5.6	5.6	5.6	5.6	5.6	5.7
ACTUAL CH2O CONCENTRATION PPM DRY	1.1	1.1	1.1	1.1	1.1	1.1	1.1
NOX MOLES PER HOUR	1.25	1.24	1.23	1.22	1.23	1.21	1.20
CO MOLES PER HOUR	0.21	0.21	0.22	0.22	0.21	0.22	0.22
VOC MOLES PER HOUR	0.21	0.21	0.22	0.22	0.21	0.22	0.22
CH2O MOLES PER HOUR	0.04	0.04	0.04	0.04	0.04	0.04	0.04
NOX AS NO2 MOLECULAR WEIGHT	46	46	46	46	46	46	46
CO MOLECULAR WEIGHT	28	28	28	28	28	28	28
VOC (as CH4) MOLECULAR WEIGHT	16	16	16	16	16	16	16
CH2O MOLECULAR WEIGHT	30	30	30	30	30	30	30
NOX EMISSIONS LBS/HOUR	57.7	57.1	56.5	56.1	56.5	55.8	55.4
CO EMISSIONS LBS/HOUR	6.0	6.0	6.0	6.1	6.0	6.0	6.1
VOC EMISSIONS LBS/HOUR	3.4	3.4	3.4	3.5	3.4	3.5	3.5
CH2O EMISSIONS LBS/HOUR	1.3	1.3	1.3	1.3	1.3	1.3	1.3
PARTICULATE EMISSIONS LBS/HR	2.8	2.8	2.8	2.8	2.8	2.8	2.8
OPERATING HOURS PER YEAR	8248	8248	8248	8248	8248	8248	8248
RAW NOX EMISSIONS TONS/YEAR	238.0	235.5	233.1	231.4	232.9	230.3	228.5
RAW CO EMISSIONS TONS/YEAR	24.7	24.7	24.8	25.0	24.8	24.9	25.1
RAW VOC EMISSIONS TONS/YEAR	14.1	14.1	14.2	14.3	14.2	14.3	14.3
RAW CH2O EMISSIONS TONS/YEAR	5.3	5.3	5.3	5.3	5.3	5.3	5.4
PARTICULATE EMISSIONS TONS/YEAR	11.5	11.5	11.6	11.6	11.6	11.6	11.7
NOX SCR REDUCTION %	95%	95%	95%	95%	95%	95%	95%
CO CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%
VOC CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%
CH2O CATALYST REDUCTION %	90%	90%	90%	90%	90%	90%	90%
NOX EMISSIONS AFTER CATALYST TONS/YEAR	11.9	11.8	11.7	11.6	11.6	11.5	11.4
CO EMISSIONS AFTER CATALYST TONS/YEAR	2.5	2.5	2.5	2.5	2.5	2.5	2.5
VOC EMISSIONS AFTER CATALYST TONS/YEAR	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CH2O EMISSIONS AFTER CATALYST TONS/YEAR	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Ammonia injection Requirements lbsd/hr as (100% NH3)	**29.3**	**29.1**	**28.7**	**28.5**	**28.7**	**28.4**	**28.1**

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	1	2	3	4	5	6	7	8	9	10	11	12	13	14
SO2 Emissions														
Heat Input (MMBtu/hr)	496.1559	496.19878	496.23309	485.59295	485.66172	485.71331	475.31701	475.411859	475.49809	465.504544	465.66021	465.78128	455.62927	455.85487
AP-42 SO2 Factor (lb/MMBtu)	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03
SO2 (lb/hr)	1.69	1.69	1.69	1.65	1.65	1.65	1.62	1.62	1.62	1.58	1.58	1.58	1.55	1.55
SO2 (tpy)	7.39	7.39	7.39	7.23	7.23	7.23	7.08	7.08	7.08	6.93	6.93	6.94	6.79	6.79
Non-formaldehyde HAP Emissions														
Heat Input (MMBtu/hr)	496.1559	496.19878	496.23309	485.59295	485.66172	485.71331	475.31701	475.411859	475.49809	465.504544	465.66021	465.78128	455.62927	455.85487
AP-42 HAP Factor (lb/MMBtu)	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04
Other HAP (lb/hr)	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.14
Other HAP (tpy)	0.68	0.68	0.68	0.67	0.67	0.67	0.66	0.66	0.66	0.64	0.64	0.64	0.63	0.63
H2SO4 Emissions														
H2SO4 (tpy)	0.37	0.37	0.37	0.36	0.36	0.36	0.35	0.35	0.35	0.35	0.35	0.35	0.34	0.34
Ammonia Emissions														
Ammonia Slip (ppmvd)	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Ammonia MW (lb/lbmol)	17	17	17	17	17	17	17	17	17	17	17	17	17	17
NH3 (lb/hr)	3.26	3.26	3.26	3.21	3.21	3.21	3.16	3.16	3.16	3.11	3.11	3.11	3.07	3.06
NH3 (tpy)	14.27	14.27	14.26	14.05	14.05	14.05	13.84	13.84	13.83	13.63	13.63	13.62	13.43	13.42
Startup/Shutdown														
Number of Startups	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4
Number of Shutdowns	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4
NOX SUSD Annual PTE (tpy)	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968
CO SUSD Annual PTE (tpy)	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296
NMVOC SUSD Annual PTE (tpy)	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008
PM SUSD Annual PTE (tpy)	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
SO2 Emissions															
Heat Input (MMBtu/hr)	456.02841	446.08573	446.40789	446.60909	446.55398	445.14598	444.07748	437.46124	434.64458	432.55548	426.16936	423.12507	420.92408	415.72121	412.53921
AP-42 SO2 Factor (lb/MMBtu)	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03
SO2 (lb/hr)	1.55	1.52	1.52	1.52	1.52	1.51	1.51	1.49	1.48	1.47	1.45	1.44	1.43	1.41	1.40
SO2 (tpy)	6.79	6.64	6.65	6.65	6.65	6.63	6.61	6.51	6.47	6.44	6.35	6.30	6.27	6.19	6.14
Non-formaldehyde HAP Emissions															
Heat Input (MMBtu/hr)	456.02841	446.08573	446.40789	446.60909	446.55398	445.14598	444.07748	437.46124	434.64458	432.55548	426.16936	423.12507	420.92408	415.72121	412.53921
AP-42 HAP Factor (lb/MMBtu)	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04
Other HAP (lb/hr)	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.13
Other HAP (tpy)	0.63	0.62	0.62	0.62	0.62	0.61	0.61	0.60	0.60	0.60	0.59	0.58	0.58	0.57	0.57
H2SO4 Emissions															
H2SO4 (tpy)	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.31	0.31	0.31
Ammonia Emissions															
Ammonia Slip (ppmvd)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Ammonia MW (lb/lbmol)	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
NH3 (lb/hr)	3.06	3.02	3.02	3.01	3.00	2.99	2.98	2.94	2.92	2.90	2.86	2.84	2.82	2.78	2.75
NH3 (tpy)	13.41	13.22	13.21	13.19	13.13	13.09	13.06	12.88	12.79	12.72	12.54	12.43	12.34	12.19	12.06
Startup/Shutdown															
Number of Startups	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4
Number of Shutdowns	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4	614.4
NOX SUSD Annual PTE (tpy)	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968
CO SUSD Annual PTE (tpy)	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296
NMVOC SUSD Annual PTE (tpy)	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008
PM SUSD Annual PTE (tpy)	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	30	31	32	33	34	35	36
SO2 Emissions							
Heat Input (MMBtu/hr)	410.2433	406.0776	402.0698	398.9571	401.6621	397.2995	394.2302
AP-42 SO2 Factor (lb/MMBtu)	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03	3.40E-03
SO2 (lb/hr)	1.39	1.38	1.37	1.36	1.37	1.35	1.34
SO2 (tpy)	6.11	6.05	5.99	5.94	5.98	5.92	5.87
Non-formaldehyde HAP Emissions							
Heat Input (MMBtu/hr)	410.2433	406.0776	402.0698	398.9571	401.6621	397.2995	394.2302
AP-42 HAP Factor (lb/MMBtu)	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04	3.15E-04
Other HAP (lb/hr)	0.13	0.13	0.13	0.13	0.13	0.13	0.12
Other HAP (tpy)	0.57	0.56	0.55	0.55	0.55	0.55	0.54
H2SO4 Emissions							
H2SO4 (tpy)	0.31	0.30	0.30	0.30	0.30	0.30	0.29
Ammonia Emissions							
Ammonia Slip (ppmvd)	5	5	5	5	5	5	5
Ammonia MW (lb/lbmol)	17	17	17	17	17	17	17
NH3 (lb/hr)	2.73	2.70	2.66	2.63	2.66	2.62	2.58
NH3 (tpy)	11.96	11.83	11.65	11.51	11.66	11.45	11.31
Startup/Shutdown							
Number of Startups	614.4	614.4	614.4	614.4	614.4	614.4	614.4
Number of Shutdowns	614.4	614.4	614.4	614.4	614.4	614.4	614.4
NOX SUSD Annual PTE (tpy)	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968	5.95968
CO SUSD Annual PTE (tpy)	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296	8.23296
NMVOC SUSD Annual PTE (tpy)	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008	0.43008
PM SUSD Annual PTE (tpy)	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536	0.1536

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Ammonium Sulfate Contribution														
SO2 MW (lb/lbmol)	64	64	64	64	64	64	64	64	64	64	64	64	64	64
SO3 MW (lb/lbmol)	80	80	80	80	80	80	80	80	80	80	80	80	80	80
H2SO4 MW (lb/lbmol)	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ammonium Sulfate MW (lb/lbmol)	132	132	132	132	132	132	132	132	132	132	132	132	132	132
SO2 to SO3 Conversion Rate in SCR/OC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
PM from Ammonium Sulfate (lb/hr)	0.70	0.70	0.70	0.68	0.68	0.68	0.67	0.67	0.67	0.65	0.65	0.65	0.64	0.64
PM from Ammonium Sulfate (tpy)	3.0479	3.0481	3.0483	2.98	2.98	2.98	2.92	2.92	2.92	2.86	2.86	2.86	2.80	2.80
GHG Emissions														
Heat Input (MMBtu/hr)	496.1559	496.19878	496.23309	485.59295	485.66172	485.71331	475.31701	475.411859	475.49809	465.504544	465.66021	465.78128	455.62927	455.85487
CO2 GWP	1	1	1	1	1	1	1	1	1	1	1	1	1	1
CH4 GWP	25	25	25	25	25	25	25	25	25	25	25	25	25	25
N2O GWP	298	298	298	298	298	298	298	298	298	298	298	298	298	298
Part 98 CH4 Factor (kg/MMBtu)	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03
Part 98 N2O Factor (kg/MMBtu)	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04
CO2 (tpy)	3.14E+05	3.14E+05	3.13E+05	3.07E+05	3.07E+05	3.07E+05	3.01E+05	3.01E+05	3.01E+05	2.94E+05	2.94E+05	2.94E+05	2.88E+05	2.88E+05
CH4 (tpy)	4.79	4.79	4.79	4.69	4.69	4.69	4.59	4.59	4.59	4.50	4.50	4.50	4.40	4.40
N2O (tpy)	0.48	0.48	0.48	0.47	0.47	0.47	0.46	0.46	0.46	0.45	0.45	0.45	0.44	0.44
Total Emissions														
NOX (tpy)	20.4	20.344	20.335	20.0	20.0	20.0	19.7	19.7	19.7	19.5	19.5	19.5	19.2	19.2
CO (tpy)	10.74	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
VOC (tpy)	1.8605	1.8599	1.8596	1.85	1.85	1.85	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
PM (tpy)	14.863	14.858	14.856	14.7	14.7	14.7	14.6	14.6	14.6	14.5	14.5	14.5	14.3	14.3
SO2 (tpy)	7.39	7.4	7.4	7.2	7.2	7.2	7.1	7.1	7.1	6.9	6.9	6.9	6.8	6.8
H2SO4 (tpy)	0.37	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
NH3 (tpy)	14.3	14.3	14.3	14.1	14.1	14.1	13.8	13.8	13.8	13.6	13.6	13.6	13.4	13.4
CH2O (tpy)	0.569724	0.5694655	0.5693362	0.5659608	0.5657015	0.5663509	0.5620668	0.562455268	0.5629742	0.55946724	0.5595939	0.5599818	0.5555617	0.5562037
Total HAP (tpy)	1.255	1.254	1.254	1.24	1.24	1.24	1.22	1.22	1.22	1.20	1.20	1.20	1.18	1.19
CO2e (tpy)	313792	313791.59	313695.11	307039.17	307039.2	307543.81	300940.97	300941.0229	300845.67	294493.764	294493.85	294493.91	288294.08	288294.2

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Ammonium Sulfate Contribution															
SO2 MW (lb/lbmol)	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
SO3 MW (lb/lbmol)	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
H2SO4 MW (lb/lbmol)	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Ammonium Sulfate MW (lb/lbmol)	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
SO2 to SO3 Conversion Rate in SCR/OC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
PM from Ammonium Sulfate (lb/hr)	0.64	0.63	0.63	0.63	0.63	0.62	0.62	0.61	0.61	0.61	0.60	0.59	0.59	0.58	0.58
PM from Ammonium Sulfate (tpy)	2.80	2.74	2.74	2.74	2.74	2.73	2.73	2.69	2.67	2.66	2.62	2.60	2.59	2.55	2.53
GHG Emissions															
Heat Input (MMBtu/hr)	456.02841	446.08573	446.40789	446.60909	446.55398	445.14598	444.07748	437.46124	434.64458	432.55548	426.16936	423.12507	420.92408	415.72121	412.53921
CO2 GWP	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
CH4 GWP	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
N2O GWP	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
Part 98 CH4 Factor (kg/MMBtu)	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03
Part 98 N2O Factor (kg/MMBtu)	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04
CO2 (tpy)	2.88E+05	2.82E+05	2.82E+05	2.82E+05	2.82E+05	2.81E+05	2.81E+05	2.77E+05	2.75E+05	2.73E+05	2.69E+05	2.67E+05	2.66E+05	2.63E+05	2.61E+05
CH4 (tpy)	4.40	4.31	4.31	4.31	4.31	4.30	4.29	4.22	4.20	4.18	4.12	4.09	4.06	4.01	3.98
N2O (tpy)	0.44	0.43	0.43	0.43	0.43	0.43	0.43	0.42	0.42	0.42	0.41	0.41	0.41	0.40	0.40
Total Emissions															
NOX (tpy)	19.2	18.9	18.9	18.9	18.9	18.9	18.8	18.6	18.6	18.5	18.3	18.2	18.2	18.0	17.9
CO (tpy)	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
VOC (tpy)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
PM (tpy)	14.4	14.2	14.2	14.2	14.3	14.3	14.3	14.2	14.2	14.2	14.2	14.2	14.2	14.1	14.2
SO2 (tpy)	6.8	6.6	6.6	6.7	6.7	6.6	6.6	6.5	6.5	6.4	6.3	6.3	6.3	6.2	6.1
H2SO4 (tpy)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
NH3 (tpy)	13.4	13.2	13.2	13.2	13.1	13.1	13.1	12.9	12.8	12.7	12.5	12.4	12.3	12.2	12.1
CH2O (tpy)	0.557109	0.5526821	0.5537087	0.5542192	0.5562783	0.5567939	0.5566559	0.5561078	0.5568849	0.557006	0.556589	0.5570987	0.5581462	0.5586625	0.5603791
Total HAP (tpy)	1.19	1.17	1.17	1.17	1.17	1.17	1.17	1.16	1.16	1.15	1.14	1.14	1.14	1.13	1.13
CO2e (tpy)	288682.5	282244.84	282626.91	282533.36	282445.66	281694.35	281130.87	276817.03	275225.97	273454.27	269541.38	267675.99	266183.8	262847.06	261147.16

Table N.5 - SGT-800 Turbine Detailed Run Data

Run identity	30	31	32	33	34	35	36
Ammonium Sulfate Contribution							
SO2 MW (lb/lbmol)	64	64	64	64	64	64	64
SO3 MW (lb/lbmol)	80	80	80	80	80	80	80
H2SO4 MW (lb/lbmol)	98	98	98	98	98	98	98
Ammonium Sulfate MW (lb/lbmol)	132	132	132	132	132	132	132
SO2 to SO3 Conversion Rate in SCR/OC	20%	20%	20%	20%	20%	20%	20%
PM from Ammonium Sulfate (lb/hr)	0.58	0.57	0.56	0.56	0.56	0.56	0.55
PM from Ammonium Sulfate (tpy)	2.52	2.49	2.47	2.45	2.47	2.44	2.42
GHG Emissions							
Heat Input (MMBtu/hr)	410.2433	406.0776	402.0698	398.9571	401.6621	397.2995	394.2302
CO2 GWP	1	1	1	1	1	1	1
CH4 GWP	25	25	25	25	25	25	25
N2O GWP	298	298	298	298	298	298	298
Part 98 CH4 Factor (kg/MMBtu)	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03	1.00E-03
Part 98 N2O Factor (kg/MMBtu)	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04	1.00E-04
CO2 (tpy)	2.59E+05	2.57E+05	2.54E+05	2.52E+05	2.54E+05	2.51E+05	2.49E+05
CH4 (tpy)	3.96	3.92	3.88	3.85	3.88	3.84	3.81
N2O (tpy)	0.40	0.39	0.39	0.39	0.39	0.38	0.38
Total Emissions							
NOX (tpy)	17.9	17.7	17.6	17.5	17.6	17.5	17.4
CO (tpy)	10.7	10.7	10.7	10.7	10.7	10.7	10.7
VOC (tpy)	1.8	1.8	1.8	1.9	1.8	1.9	1.9
PM (tpy)	14.2	14.2	14.2	14.2	14.2	14.2	14.3
SO2 (tpy)	6.1	6.0	6.0	5.9	6.0	5.9	5.9
H2SO4 (tpy)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
NH3 (tpy)	12.0	11.8	11.6	11.5	11.7	11.5	11.3
CH2O (tpy)	0.5621113	0.562508	0.565069	0.567929	0.564392	0.567795	0.570825
Total HAP (tpy)	1.13	1.12	1.12	1.12	1.12	1.12	1.11
CO2e (tpy)	259468.55	257043.4	254582.1	252246.8	254059.1	251219.1	249210.4

Table N.6 - LM6000PG Turbine Potential Emissions Summary - Impact of SCR and OxCat on PM Emissions

INPUT PARAMETERS

Maximum Heat Input	482.60	MMBtu/hr, HHV	
$PM_{10}/PM_{2.5}$ Emission Factor	6.60E-03	lb/MMBtu	*AP-42 Table 3.1-2a*
SO_2 Emission Factor	3.40E-03	lb/MMBtu	*AP-42 Table 3.1-2a, footnote h*
SO_2 Emissions	1.64	lb/hr	

SO_2 TO SO_3 CONVERSION RATES (MOLAR BASIS)

SCR/Oxidation Catalyst	20.0%	*Engineering Estimate*

MOLECULAR WEIGHTS

SO_2	64	lb/lbmol
SO_3	80	lb/lbmol
H_2SO_4	98	lb/lbmol
Ammonium Sulfate, $(NH_4)_2SO_4$	132	lb/lbmol
Ammonium Bisulfate, NH_4HSO_4	115	lb/lbmol

$PM_{10}/PM_{2.5}$ EMISSIONS

Pollutants	*(lb/hr)*	
$PM_{10}/PM_{2.5}$	3.19	
Ammonium Sulfate	0.68	*Assumes all ammonium salts are ammonium sulfate (conservative assumption)*
$PM_{10}/PM_{2.5}$ including ammonia salts [a]	3.86	

[a] *The SCR and oxidation catalysts are expected to convert a significant portion of SO_2 to SO_3 which is available to react with NH_3 and form ammonium sulfate or ammonium bisulfate post combustion.*

Table N.7 - SGT-800 Turbine Potential Emissions Summary - Impact of SCR and OxCat on PM Emissions

INPUT PARAMETERS

Maximum Heat Input	496.16	MMBtu/hr, HHV	
$PM_{10}/PM_{2.5}$ Emission Factor	2.50	lb/hr @ 15% O_2	*See Table N.5*
Exhaust Moisture Content	6.02	%	*See Table N.5*
Exhaust O_2 Content	13.37	%	*See Table N.5*
SO_2 Emission Factor	3.40E-03	lb/MMBtu	*AP-42 Table 3.1-2a, footnote h*
SO_2 Emissions	1.69	lb/hr	

SO_2 TO SO_3 CONVERSION RATES (MOLAR BASIS)

SCR/Oxidation Catalyst	20.0%	*Engineering Estimate*

MOLECULAR WEIGHTS

SO_2	64	lb/lbmol
SO_3	80	lb/lbmol
H_2SO_4	98	lb/lbmol
Ammonium Sulfate, $(NH_4)_2SO_4$	132	lb/lbmol
Ammonium Bisulfate, NH_4HSO_4	115	lb/lbmol

$PM_{10}/PM_{2.5}$ EMISSIONS

Pollutants	*(lb/hr)*	
$PM_{10}/PM_{2.5}$	2.83	*Emissions (lb/hr) = Guarantee (lb/hr) x [20.9 - Oxygen Content / (100 - Moisture Content)] x 100 / [20.9 - 15]*
Ammonium Sulfate	0.70	*Assumes all ammonium salts are ammonium sulfate (conservative assumption)*
$PM_{10}/PM_{2.5}$ including ammonia salts [a]	3.52	

[a] *The SCR and oxidation catalysts are expected to convert a significant portion of SO_2 to SO_3 which is available to react with NH_3 and form ammonium sulfate or ammonium bisulfate post combustion.*

Table N.8 - Duct Burner Turbine Potential Emissions Summary

DIMENSIONAL ANALYSIS

Mass Conversion	0.4536	kg/lb	*NIST SP1038*
Mass Conversion	2,000	lb/ton	*NIST SP1038*
Time Conversion	24	hr/day	
Molecular Weight of NH_3	17	lb/lbmol	
Molecular Weight of Sulfur	32	lb/lbmol	
Molecular Weight of NO_2	46	lb/lbmol	
Molecular Weight of VOC	12	lb/lbmol (as carbon)	
Molecular Weight of CO	28	lb/lbmol	
Molar Volume @STP	385.2	scf/lbmol	
Fw	10,610	wscf/mmbtu	*EPA Method 19 - Table 19-2 - Natural Gas*
Fd	8,710	dscf/mmbtu	*EPA Method 19 - Table 19-2 - Natural Gas*
GWP - CO_2	1	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - CH_4	25	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - N_2O	298	GWP	*40 CFR 98 Subpart A, Table A-1*

OPERATING PARAMETERS

Fuel Used	Natural Gas	
Heating Value	1,357	MMBtu/mmscf
Maximum Potential Operating Hours	1,745	hr/yr

DUCT BURNER EMISSION GUARANTEES

VOC	1.0	ppmvd	*OxCat Vendor Garantuee*
NO_X	2.0	ppmvd at 15% O2	*SCR Vendor Garantuee*
CO	2.0	ppmvd at 15% O2	*OxCat Vendor Garantuee*
Ammonia	5.0	ppm	*Assumed Ammonia Slip*
SO_2	5.88E-04	lb/MMBtu	*AP-42 Table 1.4-2 normalized using a standard heat content of 1,020 Btu/scf*
Sulfuric Acid Mist	2.94E-05	lb/MMBtu	*5% of SO_2*
Total PM/PM_{10}/$PM_{2.5}$	7.45E-03	lb/MMBtu	*Sum of filterable and condensable*
PM Condensable	5.59E-03	lb/MMBtu	*AP-42 Table 1.4-2 normalized using a standard heat content of 1,020 Btu/scf*
PM_{10}/$PM_{2.5}$ (Filterable)	0.002	lb/MMBtu	*AP-42 Table 1.4-2 normalized using a standard heat content of 1,020 Btu/scf*
Formaldehyde	7.35E-05	lb/MMBtu	*AP-42 Table 1.4-3 normalized using a standard heat content of 1,020 Btu/scf*
Lead	4.90E-07	lb/MMBtu	*AP-42 Table 1.4-3 normalized using a standard heat content of 1,020 Btu/scf*
Hexane	1.27E-06	lb/MMBtu	*AB 2588 - Ventura County Air Pollution Control Board, May 17, 2001 normalized using a standard heat content of 1,020 Btu/scf*
Total HAP	8.81E-05	lb/MMBtu	*AP-42 Table 1.4-3 and AB 2588 (for hexane) normalized using a standard heat content of 1,020 Btu/scf*
CO_2	53.06	kg/MMBtu	*40 CFR 98, Subpart C, Table C-1 for natural gas*
CH_4	1.00E-03	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for natural gas*
N_2O	1.00E-04	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for natural gas*

				Duct Burner Emissions (tpy)[a]														
EU ID	Max Heat Input Capacity (MMBTU/Hr)	Exhaust Flow Rate (scfm) [b]	Exhaust Flow Rate (dscfm) [b]	NO_x [c]	CO [c]	SO_2	PM	VOC[g]	Ammonia [d]	Hexane	Formaldehyde	Sulfuric Acid Mist	Lead	Total HAPs	CO_2 [e]	CH_4 [e]	N_2O [e]	CO_2e [f]
DB1	475.1	84013.52	68968.68	3.05	1.86	0.24	3.19	0.11	0.97	5.28E-04	0.03	0.01	2.03E-04	0.04	48,490	0.91	9.14E-02	48,540
DB2	475.1	84013.52	68968.68	3.05	1.86	0.24	3.19	0.11	0.97	5.28E-04	0.03	0.01	2.03E-04	0.04	48,490	0.91	9.14E-02	48,540
DB3	475.1	84013.52	68968.68	3.05	1.86	0.24	3.19	0.11	0.97	5.28E-04	0.03	0.01	2.03E-04	0.04	48,490	0.91	9.14E-02	48,540
DB4	475.1	84013.52	68968.68	3.05	1.86	0.24	3.19	0.11	0.97	5.28E-04	0.03	0.01	2.03E-04	0.04	48,490	0.91	9.14E-02	48,540
			Pollutant Total:	12.22	7.44	0.98	12.76	0.45	3.88	2.11E-03	0.12	0.05	8.13E-04	0.15	193,960	3.66	0.37	194,160

[a] *Annual Emissions (tons/yr) = Annual Emissions (tons/yr) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) / 2,000 (lb/ton)*

[b] *Exhaust Flow Rate (scfm) = Max Heat Input Capacity (MMBtu/hr) / 60 (min/hr) x F_w (scf/MMBtu)*

Exhaust Flow Rate (dscfm) = Max Heat Input Capacity (MMBtu/hr) / 60 (min/hr) x F_d (dcf/MMBtu)

[c] *NO_X or CO Emissions (lb/hr) = NO_X or CO (ppmvd) / 1,000,000 x [(20.9 - 0) / (20.9 - 15)] x Exhaust Flow Rate (dcfm) x Molecular Weight of NO_X or CO (lb/lbmol) x 60 (min/hr) / Molar Volume @ STP (lbmol/scf) x Operating Hours (hr/yr) / 2,000 (lb/ton)*

Fd factors were developed based on the 0% Oxygen content. However, emission guarantees are at 15% oxygen content. As such, an adjustment factor has been added.

[d] *Ammonia Emissions (lb/hr) = Ammonia (ppmv) / 1,000,000 x Exhaust Flow Rate (scfm) x Molecular Weight of Ammonia (lb/lbmol) x 60 (min/hr) / Molar Volume @ STP (lbmol/scf) x Operating Hours (hr/yr) / 2,000 (lb/ton)*

[e] *GHG Emission Rate (tpy) = Heat Input (MMBtu/hr) × Emission Factor (kg/MMBtu) × Operating hours (hr/yr) / 0.45359237 (kg/lb) / 2,000 (lb/ton)*

[f] *CO_2e Emissions (tpy) = Annual CO_2 Emission (tpy) x CO_2 GWP + Annual CH_4 Emissions (tpy) x CH_4 GWP + Annual N_2O Emissions (tpy) x N_2O GWP*

[g] *VOC Emissions (tpy) = VOC (ppmvd) / 1,000,000 x Exhaust Flow Rate (dcfm) x Molecular Weight of VOC (lb/lbmol) x 60 (min/hr) / Molar Volume @ STP (lbmol/scf) x Operating Hours (hr/yr) / 2,000 (lb/ton)*

Table N.9 - Duct Burners Potential Emissions Summary - Impact of SCR and OxCat on PM Emissions

INPUT PARAMETERS

Maximum Heat Input	475.10	MMBtu/hr, HHV	
$PM_{10}/PM_{2.5}$ Emission Factor	7.45E-03	lb/MMBtu	*Sum of filterable and condensable*
SO_2 Emission Factor	5.88E-04	lb/MMBtu	*AP-42 Table 1.4-2 normalized using a standard heat content of 1,020 Btu/scf*
SO_2 Emissions	0.28	lb/hr	

SO_2 TO SO_3 CONVERSION RATES (MOLAR BASIS)

SCR/Oxidation Catalyst	20.0%	*Engineering Estimate*

MOLECULAR WEIGHTS

SO_2	64	lb/lbmol
SO_3	80	lb/lbmol
H_2SO_4	98	lb/lbmol
Ammonium Sulfate, $(NH_4)_2SO_4$	132	lb/lbmol
Ammonium Bisulfate, NH_4HSO_4	115	lb/lbmol

$PM_{10}/PM_{2.5}$ EMISSIONS

Pollutants	*(lb/hr)*	
$PM_{10}/PM_{2.5}$	3.54	
Ammonium Sulfate	0.12	*Assumes all ammonium salts are ammonium sulfate (conservative assumption)*
$PM_{10}/PM_{2.5}$ including ammonia salts [a]	3.66	

[a] *The SCR and oxidation catalysts are expected to convert a significant portion of SO_2 to SO_3 which is available to react with NH_3 and form ammonium sulfate or ammonium bisulfate post combustion.*

Table N.10 - Heater Potential Emissions Summary

OPERATING PARAMETERS

Fuel Used	Natural Gas		
Standard Heating Value	1,357	MMBtu/mmscf	*Engineering Estimate*
Maximum Potential Operating Hours	8,760	hr/yr	

EMISSION FACTORS

Pollutant	*Emission Factors*	*Units*	*Source*
NOx	50	lb/MMscf	*Controlled Small Boilers - Low NO_X Burners, AP-42 Section 1.4, Table 1.4-1*
CO	84	lb/MMscf	*Uncontrolled Small Boilers, AP-42 Section 1.4, Table 1.4-1*
SO2	0.6	lb/MMscf	*AP-42 Section 1.4, Table 1.4-2*
Total PM/PM10/PM2.5	7.6	lb/MMscf	*AP-42 Section 1.4, Table 1.4-2*
PM Condensable	5.7	lb/MMscf	*AP-42 Section 1.4, Table 1.4-2*
PM10/PM2.5 (Filterable)	1.9	lb/MMscf	*AP-42 Section 1.4, Table 1.4-2*
VOC	5.5	lb/MMscf	*AP-42 Section 1.4, Table 1.4-2*
n-Hexane	6.30E-03	lb/MMscf	*AB 2588 - Ventura County Air Pollution Control Board, May 17, 2001*
Total HAP	0.09	lb/MMscf	*AP-42 Section 1.4, Tables 1.4-3 and 1.4-4 and AB 2588 (for hexane)*
CO2	53.06	kg/MMBtu	*40 CFR 98, Subpart C, Table C-1 for natural gas*
CH4	1.00E-03	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for natural gas*
N2O	1.00E-04	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for natural gas*
GWP - CO2	1	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - CH4	25	GWP	*40 CFR 98 Subpart A, Table A-1*
GWP - N2O	298	GWP	*40 CFR 98 Subpart A, Table A-1*

Heater Emissions (tpy)[a]														
EU ID	Max Heat Input Capacity (MMBTU/Hr)	Fuel Consumption (MMscf/Hr)[d]	NO_x	CO	SO_2	PM	VOC	Hexane	Lead	Formaldehyde	Total HAPs	CO_2[b]	CH_4[b]	N_2O[b]	CO_2e[c]
FH1	9.9	7.30E-03	2.13	3.57	0.03	0.32	0.23	2.68E-04	2.13E-05	3.19E-03	4.03E-03	5,072	0.10	9.56E-03	5,078
FH2	9.9	7.30E-03	2.13	3.57	0.03	0.32	0.23	2.68E-04	2.13E-05	3.19E-03	4.03E-03	5,072	0.10	9.56E-03	5,078
		Pollutant Total:	4.25	7.14	0.05	0.65	0.47	5.36E-04	4.25E-05	0.01	8.06E-03	10,145	0.19	0.02	10,155

a Annual Emissions (tons/yr) = Fuel Usage (mmscf/hr) × Emission Factor (lb/mmscf) x 8,760 (hr/yr) / 2,000 (lb/ton)

b GHG Emission Rate (tpy) = Heat Input (MMBtu/hr) × Emission Factor (kg/MMBtu) × 8,760 (hr/yr) / 0.45359237 (kg/lb) / 2,000 (lb/ton)

c CO2e Emissions (tpy) = Annual CO2 Emission (tpy) x CO2 GWP + Annual CH4 Emissions (tpy) x CH4 GWP + Annual N2O Emissions (tpy) x N2O GWP

d Maximum Fuel Usage = Maximum Heat Input Capacity (MMBtu/hr) / Higher Heating Value (MMBtu/mmscf)

Table N.11 - Emergency Diesel Generator Potential Emissions

DIMENSIONAL ANALYSIS

Mass Conversion	0.45359237	kg/lb	*NIST1038*
Mass Conversion	453.59237	g/lb	*NIST1038*
Mass Conversion	2,000	lb/ton	*NIST1038*
Power Conversion	0.746	kW/hp	
Time Conversion	24	hr/day	

OPERATING PARAMETERS

Fuel Used	Diesel		
Genset Power Rating	1,000	kW	*Manufacturer's specifications*
Efficiency Factor	0.8		*Manufacturer's specifications*
Engine Power Rating	1,250	kW	*= Power Rating (kW) / Efficiency Factor*
Engine Power Rating	1,676	hp	*= Power Rating (kW) / Power Conversion (kW/hp) / Efficiency Factor*
Maximum Heat Input Capacity	11.73	MMBtu/hr	
Maximum Operating Hours	100	hr/yr	*Emergency Engine*

EMISSION FACTORS

Pollutant	*Emission Factor*	*Units*	*Source*
NO_X + NMHC	8.00	g/kW-hr	*"Owner/Operator Guidance Document for the NSPS for Stationary Compression Ignition Internal Combustion Engines," U.S. EPA OAQPS, 12/08 Table 4*
NO_X to NO_X + NMHC Ratio	74.60%		*Linear relationship of NOx to NMHC from Table 1 in NSPS IIII*
NMHC to NO_X + NMHC Ratio	25.40%		*Linear relationship of NOx to NMHC from Table 1 in NSPS IIII*
NO_X	5.97	g/kW-hr	*= Combined factor x Ratio*
CO	4.40	g/kW-hr	*"Owner/Operator Guidance Document for the NSPS for Stationary Compression Ignition Internal Combustion Engines," U.S. EPA OAQPS, 12/08 Table 4*
SO_2	2.05E-03	lb/hp-hr	*AP-42, Section 3.3, Table 3.3-1 (selected for independence from sulfur content)*
TOC	2.03	g/kW-hr	*= Combined factor x Ratio*
Filterable $PM/PM_{10}/PM_{2.5}$	0.25	g/kW-hr	*"Owner/Operator Guidance Document for the NSPS for Stationary Compression Ignition Internal Combustion Engines," U.S. EPA OAQPS, 12/08 Table 4*
Condensable PM Factor	7.70E-03	lb/MMBtu	*AP-42, Section 3.4, Table 3.4-2 (selected to speciate condensable PM)*
Filterable PM Factor	6.20E-02	lb/MMBtu	*AP-42, Section 3.4, Table 3.4-2 (selected to speciate filterable PM)*
Condensable PM	3.10E-02	g/kW-hr	*Ratio of condensable and filterable factors from Table 3.4-2*
Total $PM/PM_{10}/PM_{2.5}$	2.81E-01	g/kW-hr	*= Filterable PM/PM $_{10}$ EF (lb/hp-hr) + Condensable PM EF (lb/hp-hr)*
Formaldehyde	1.18E-03	lb/MMBtu	*AP-42, Section 3.3, Table 3.3-2 (selected to maximize emissions)*
Total HAP	3.87E-03	lb/MMBtu	*AP-42, Section 3.3, Table 3.3-2 (selected to maximize emissions)*
CO_2	73.96	kg/MMBtu	*40 CFR 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2*
CH_4	3.00E-03	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for Petroleum*
N_2O	6.00E-04	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for Petroleum*
GWP - CO_2	1		*Table A-1 of 40 CFR 98, Subpart A*
GWP - CH_4	25		*Table A-1 of 40 CFR 98, Subpart A*
GWP - N_2O	298		*Table A-1 of 40 CFR 98, Subpart A*

POTENTIAL EMISSIONS

Pollutant	*(lbs/hr)* [a]	*(lbs/day)* [a]	*(tons/yr)* [a]
NO_X	16.45	394.72	0.82
CO	12.13	291.01	0.61
SO_2 [b]	3.43	82.44	0.17
Filterable $PM/PM_{10}/PM_{2.5}$	0.69	16.53	0.03
Condensable PM	0.09	2.05	0.00
Total $PM/PM_{10}/PM_{2.5}$	0.77	18.59	0.04
VOC	5.60	134.39	0.28
Formaldehyde [c]	-	-	6.92E-04
Total HAP [c]	-	-	2.27E-03
CO_2 [d]	-	-	95.62
CH_4 [d]	-	-	3.88E-03
N_2O [d]	-	-	7.76E-04
CO_{2e} [e]	-	-	95.95

[a] *Hourly Emissions (lbs/hr)= Emission Factor (g/kW-hr) x Engine Power Rating (kW) / Mass Conversion (g/lb)*
Daily Emissions (lbs/day)= Emission Factor (g/kW-hr) x Engine Power Rating (kW) x 24 (hr/day) / Mass Conversion (g/lb)
Annual Emission (tpy)= Emission Factor (g/kW-hr) x Engine Power Rating (kW) x Maximum Operating hours (100 hr/yr) / Mass Conversion (g/lb) / 2,000 (lbs/ton)

[b] *Hourly Emissions (lbs/hr)= Emission Factor (lb/hp-hr) x Maximum Power Output (hp)*
Daily Emissions (lbs/day)= Emission Factor (lb/hp-hr) x Maximum Power Output (hp) x 24 (hr/day)
Annual Emission (tpy)= Emission Factor (lb/hp-hr) x Maximum Power Output (hp) x Maximum Operating hours (100 hr/yr) / 2,000 (lbs/ton)

[c] *Hourly Emissions (lbs/hr)= Emission Factor (lb/MMBtu) x Maximum Power Output (MMBtu/hr)*
Daily Emissions (lbs/day)= Emission Factor (lb/MMBtu) x Maximum Power Output (MMBtu/hr) x 24 (hr/day)
Annual Emission (tpy)= Emission Factor (lb/MMBtu) x Maximum Power Output (MMBtu/hr) x Maximum Operating hours (100 hr/yr) / 2,000 (lbs/ton)

[d] *Annual Emissions (tons/yr) = Emission Factor (kg/MMBtu) x Maximum Heat Input Capacity (MMBtu/hr) x Maximum Operating hours (100 hr/yr) / 0.4536 (kg/lb) / 2,000 (lbs/ton)*

[e] *CO_2e Emissions (tpy) = Annual CO_2 Emission (tpy) x CO_2 GWP + Annual CH_4 Emissions (tpy) x CH_4 GWP + Annual N_2O Emissions (tpy) x N_2O GWP*

Table N.12 - Emergency Diesel Fire Pump Potential Emissions

DIMENSIONAL ANALYSIS

Mass Conversion	0.45359237	kg/lb	*NIST1038*
Mass Conversion	453.59237	g/lb	*NIST1038*
Mass Conversion	2,000	lb/ton	*NIST1038*
Power Conversion	0.746	kW/hp	
Time Conversion	24	hr/day	

OPERATING PARAMETERS

Fuel Used	Diesel		
Engine Power Rating	522	kW	*= Power Rating (hp) * Power Conversion (kW/hp)*
Engine Power Rating	700	hp	
Maximum Heat Input Capacity	4.90	MMBtu/hr	
Maximum Operating Hours	100	hr/yr	*Emergency Engine*

EMISSION FACTORS

Pollutant	*Emission Factor*	*Units*	*Source*
NO_X + NMHC	5.00	g/kW-hr	*"Owner/Operator Guidance Document for the NSPS for Stationary Compression Ignition Internal Combustion Engines," U.S. EPA OAQPS, 12/08 Table 5*
NO_X to NO_X + NMHC Ratio	74.60%		*Linear relationship of NOx to NMHC from Table 1 in NSPS IIII*
NMHC to NO_X + NMHC Ratio	25.40%		*Linear relationship of NOx to NMHC from Table 1 in NSPS IIII*
NO_X	3.73	g/kW-hr	*= Combined factor x Ratio*
CO	4.40	g/kW-hr	*"Owner/Operator Guidance Document for the NSPS for Stationary Compression Ignition Internal Combustion Engines," U.S. EPA OAQPS, 12/08 Table 5*
SO_2	2.05E-03	lb/hp-hr	*AP-42, Section 3.3, Table 3.3-1 (selected for independence from sulfur content)*
TOC	1.27	g/kW-hr	*= Combined factor x Ratio*
Filterable $PM/PM_{10}/PM_{2.5}$	0.25	g/kW-hr	*"Owner/Operator Guidance Document for the NSPS for Stationary Compression Ignition Internal Combustion Engines," U.S. EPA OAQPS, 12/08 Table 5*
Condensable PM Factor	7.70E-03	lb/MMBtu	*AP-42, Section 3.4, Table 3.4-2 (selected to speciate condensable PM)*
Filterable PM Factor	6.20E-02	lb/MMBtu	*AP-42, Section 3.4, Table 3.4-2 (selected to speciate filterable PM)*
Condensable PM	3.10E-02	g/kW-hr	*Ratio of condensable and filterable factors from Table 3.4-2*
Total $PM/PM_{10}/PM_{2.5}$	2.81E-01	g/kW-hr	*= Filterable PM/PM_{10} EF (lb/hp-hr) + Condensable PM EF (lb/hp-hr)*
Formaldehyde	1.18E-03	lb/MMBtu	*AP-42, Section 3.3, Table 3.3-2 (selected to maximize emissions)*
Total HAP	3.87E-03	lb/MMBtu	*AP-42, Section 3.3, Table 3.3-2 (selected to maximize emissions)*
CO_2	73.96	kg/MMBtu	*40 CFR 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2*
CH_4	3.00E-03	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for Petroleum*
N_2O	6.00E-04	kg/MMBtu	*40 CFR 98, Subpart C, Table C-2 for Petroleum*
GWP - CO_2	1		*Table A-1 of 40 CFR 98, Subpart A*
GWP - CH_4	25		*Table A-1 of 40 CFR 98, Subpart A*
GWP - N_2O	298		*Table A-1 of 40 CFR 98, Subpart A*

POTENTIAL EMISSIONS

Pollutant	*(lbs/hr)* [a]	*(lbs/day)* [a]	*(tons/yr)* [a]
NO_X	4.29	103.06	0.21
CO	5.07	121.57	0.25
SO_2 [b]	1.44	34.44	0.07
Filterable $PM/PM_{10}/PM_{2.5}$	0.29	6.91	0.01
Condensable PM	0.04	0.86	0.00
Total $PM/PM_{10}/PM_{2.5}$	0.32	7.77	0.02
VOC	1.46	35.09	0.07
Formaldehyde [c]	-	-	2.89E-04
Total HAP [c]	-	-	9.49E-04
CO_2 [d]	-	-	39.95
CH_4 [d]	-	-	1.62E-03
N_2O [d]	-	-	3.24E-04
CO_{2e} [e]	-	-	40.09

[a] *Hourly Emissions (lbs/hr)= Emission Factor (g/kW-hr) x Engine Power Rating (kW) / Mass Conversion (g/lb)*
Daily Emissions (lbs/day)= Emission Factor (g/kW-hr) x Engine Power Rating (kW) x 24 (hr/day) / Mass Conversion (g/lb)
Annual Emission (tpy)= Emission Factor (g/kW-hr) x Engine Power Rating (kW) x Maximum Operating hours (100 hr/yr) / Mass Conversion (g/lb) / 2,000 (lbs/ton)

[b] *Hourly Emissions (lbs/hr)= Emission Factor (lb/hp-hr) x Maximum Power Output (hp)*
Daily Emissions (lbs/day)= Emission Factor (lb/hp-hr) x Maximum Power Output (hp) x 24 (hr/day)
Annual Emission (tpy)= Emission Factor (lb/hp-hr) x Maximum Power Output (hp) x Maximum Operating hours (100 hr/yr) / 2,000 (lbs/ton)

[c] *Hourly Emissions (lbs/hr)= Emission Factor (lb/MMBtu) x Maximum Power Output (MMBtu/hr)*
Daily Emissions (lbs/day)= Emission Factor (lb/MMBtu) x Maximum Power Output (MMBtu/hr) x 24 (hr/day)
Annual Emission (tpy)= Emission Factor (lb/MMBtu) x Maximum Power Output (MMBtu/hr) x Maximum Operating hours (100 hr/yr) / 2,000 (lbs/ton)

[d] *Annual Emissions (tons/yr) = Emission Factor (kg/MMBtu) x Maximum Heat Input Capacity (MMBtu/hr) x Maximum Operating hours (100 hr/yr) / 0.4536 (kg/lb) / 2,000 (lbs/ton)*

[e] *CO_2e Emissions (tpy) = Annual CO_2 Emission (tpy) x CO_2 GWP + Annual CH_4 Emissions (tpy) x CH_4 GWP + Annual N_2O Emissions (tpy) x N_2O GWP*

Table N.13 - Storage Tank Potential Emissions

Tank ID	*Tank Name*	Tank Roof Type	Annual VOC Total (tpy)	Annual Throughput (gal)	Total Losses (lbs)											
					1	2	3	4	5	6	7	8	9	10	11	12
	TK_{name}	TK_{roof}			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
OT1	*Lubricating Oil Tank #1*	*HFR*	*1.24E-03*	*1,825,000.03*	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.3	0.3	0.2	0.1	0.1
OT2	*Lubricating Oil Tank #2*	*HFR*	*1.24E-03*	*1,825,000.03*	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.3	0.3	0.2	0.1	0.1
OT3	*Lubricating Oil Tank #3*	*HFR*	*1.24E-03*	*1,825,000.03*	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.3	0.3	0.2	0.1	0.1
OT4	*Lubricating Oil Tank #4*	*HFR*	*1.24E-03*	*1,825,000.03*	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.3	0.3	0.2	0.1	0.1
OT5	*Waste Oil Tank #1*	*HFR*	*6.22E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FT1	*Generator Fuel Tank*	*HFR*	*2.45E-05*	*9,125.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FT2	*Fire Pump Fuel Tank*	*HFR*	*2.45E-05*	*9,125.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OT6	*Waste Oil Tank #2*	*HFR*	*6.22E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OT7	*Waste Oil Tank #3*	*HFR*	*6.22E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OT8	*Waste Oil Tank #4*	*HFR*	*6.22E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WS1	*Washout Sump #1*	*HFR*	*5.77E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WS2	*Washout Sump #2*	*HFR*	*5.77E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WS3	*Washout Sump #3*	*HFR*	*5.77E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WS4	*Washout Sump #4*	*HFR*	*5.77E-05*	*91,250.00*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GT1	*Glycol Tank #1*	*HFR*	*9.27E-05*	*365,000.32*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GT2	*Glycol Tank #2*	*HFR*	*9.27E-05*	*365,000.32*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GT3	*Glycol Tank #3*	*HFR*	*9.27E-05*	*365,000.32*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GT4	*Glycol Tank #4*	*HFR*	*9.27E-05*	*365,000.32*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AT1	*Ammonia Tank*	*VFR - Dome*	*1.53E+01*	*720,000.00*	1,630.6	1,741.0	2,132.4	2,520.4	2,915.7	3,269.9	3,463.8	3,389.9	3,069.3	2,527.8	2,124.3	1,781.7

Table N.14 - Piping Components Potential Emissions Summary

OPERATING PARAMETERS

Operating Hours	8,760	hr/yr

DIMENSIONAL ANALYSIS

Mass Conversion	453.59	g/lb	*NIST SP1038*
Mass Conversion	2,000	lb/ton	*NIST SP1038*
Mass Conversion	1,000	g/kg	*NIST SP1038*

EMISSION FACTORS AND OPERATING PARAMETERS

Component	Service Type	Facility Component Count	TOC Emission Factor[a] (kg/hr/component)	Average Leak Rate[b] (lb/hr)	Max Leak Rate[c] (lb/hr)	Control Efficiency	Max Leak Rate (tpy)	VOC Weight Percent (%)[d]	HAP Weight Percent (%)[d]
Connectors/Flange	Gas	250	3.90E-04	0.215	0.258	0%	1.13E+00	2.00%	0.05%

[a] *Table 2-4. Oil & Gas Production Operations Average Emission Factors, Protocol for Equipment Leak Emission Estimates, EPA 453/R-95-017, November 1995. Emission factors based on average measured TOC from component types indicated in gas or light oil service at O&G Production Operations.*

[b] *Average Leak Rate (lb/hr) = Component TOC Emission Factor (kg/hr/component) x Number of Components x 1,000 (g/kg) / 453.59 (g/lb)*

[c] *Assumes a maximum leak rate 20% greater than the measured average leak rate and accounts for control efficiency.*

[d] *Composition data estimated based on pipeline quality natural gas*

FUGITIVE COMPONENT POTENTIAL EMISSIONS

Pollutant	*(lb/hr)* [a]	*(tons/yr)* [b]
VOC	0.01	0.02
HAP	0.00	0.00

[a] *Emission Rate (lb/hr) = Σ [Component Max Leak Rate (lb/hr) x Component Pollutant Weight Percent]*

[b] *Emission Rate (tpy) = Σ [Component Max Leak Rate (tpy) x Component Pollutant Weight Percent]*

APPENDIX B. CAM APPLICABILITY ANALYSIS

Natrium Extraction and Processing Plant CAM Analysis

Emission Unit ID	Emission Point ID	Emission Unit Description	Year installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	CAM status - Subject or Exempt	Pollutant	Reason for exemption
S001	P001	Hot Oil Heater	2014	216.7 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S012	P012	Regeneration Gas Heater	2013	9.7 MMBTU/hr	No			Exempt		No controls
S013	P013	Cryogenic Hot Medium Oil (HMO) Heater	2013	26.3 MMBtu/hr	No			Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S016	P016	Hot Oil Heater	2014	61.58 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S017	P017	Hot Oil Heater	2014	61.58 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S018	P018	Hot Oil Heater	2014	61.58 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S019	P019	Hot Oil Heater	2014	61.58 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S024	P024	Regeneration Gas Heater	2018	9.7 MMBtu/hr	No			Exempt		No controls
S026	P026	Cryogenic HMO Heater	2018	26.3 MMBtu/hr	No			Exempt		No controls
S036	P036	Regeneration Gas Heater	2019	9.7 MMBTU/hr	No			Exempt		No controls
S037	P037	Cryogenic HMO Heater	2019	26.3 MMBtu/hr	No			Exempt		No controls
S040	P040	Regeneration Gas Heater	2019	19.28 MMBTU/hr	No			Exempt		No controls
S041	P041	Cryogenic HMO Heater	2019	54.67 MMBTU/hr	No			Exempt		No controls
S044	P044	Regeneration Gas Heater	2019	9.7 MMBTU/hr	No			Exempt		No controls
S045	P045	Cryogenic HMO Heater	2019	26.3 MMBtu/hr	No			Exempt		No controls
S048	P048	Regeneration Gas Heater	2019	9.7 MMBTU/hr	No			Exempt		No controls
S049	P049	Cryogenic HMO Heater	2019	26.3 MMBtu/hr	No			Exempt		No controls
S052	P052	Hot Oil Heater	2019	61.58 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S053	P053	Hot Oil Heater	2019	61.58 MMBtu/hr	Low-NO_X burner	Passive	Yes	Exempt		Uncontrolled emissions < 100 tpy for all pollutants
S056	P056	Stabilizer Heater	2019	10.09 MMBtu/hr	No			Exempt		No controls
S006	P001	Glycol Dehydration System Glycol Dehydration Flash Tank	2011	460 MMscfd	C001 & BTEX Condenser	Inherent	No	Exempt		Overheads are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the BTEX Condenser is not necessary to achieve an emission rate less than 100 tpy.

Emission Unit ID	Emission Point ID	Emission Unit Description	Year installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	CAM status - Subject or Exempt	Pollutant	Reason for exemption
TK-802	P001	Natural Gasoline Storage Tank	2011	714,000 gal	C001 & Natural Gas Blanketa	Inherent	No	Exempt		Tank uses natural gas blanket to minimize emissions. Working/breathing losses -are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the natural gas blanket is not necessary to achieve an emission rate less than 100 tpy.
TK-2802	P001	Natural Gasoline Storage Tank	2014	1,260,000 gal	C001 & Natural Gas Blanketa	Inherent	No	Exempt		Tank uses natural gas blanket to minimize emissions. Working/breathing losses -are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the natural gas blanket is not necessary to achieve an emission rate less than 100 tpy.
TK-3802	P001	Natural Gasoline Storage Tank	2019	714,000 gal	C001 & Natural Gas Blanketa	Inherent	No	Exempt		Tank uses natural gas blanket to minimize emissions. Working/breathing losses -are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the natural gas blanket is not necessary to achieve an emission rate less than 100 tpy.
TK-4802	P001	Natural Gasoline Storage Tank	2019	1,260,000 gal	C001 & Natural Gas Blanketa	Inherent	No	Exempt		Tank uses natural gas blanket to minimize emissions. Working/breathing losses -are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the natural gas blanket is not necessary to achieve an emission rate less than 100 tpy.

Emission Unit ID	Emission Point ID	Emission Unit Description	Year installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	CAM status - Subject or Exempt	Pollutant	Reason for exemption
TK-5802	P001	Natural Gasoline Storage Tank	2019	714,000 gal	C001 & Natural Gas Blanketa	Inherent	No	Exempt		Tank uses natural gas blanket to minimize emissions. Working/breathing losses -are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the natural gas blanket is not necessary to achieve an emission rate less than 100 tpy.
TK-6802	P001	Natural Gasoline Storage Tank	2019	1,260,000 gal	C001 & Natural Gas Blanket[a]	Inherent	No	Exempt		Tank uses natural gas blanket to minimize emissions. Working/breathing losses -are routed to S001 to be burned as recovered useful fuel. Therefore, per the definition of "inherent process equipment" in 40 CFR 64.1, S001 is not a control device. Operation of the natural gas blanket is not necessary to achieve an emission rate less than 100 tpy.
TK-7802	TK-7802	Refrigerated Propane Storage Tank	2019	4,200,000 gal	VRU	Inherent	N/A	Exempt		Inherent to the process.
US-800	Flare[b]	Spherical NGL Storage Tank	2011	2,142,000 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-801	Flare[b]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-804	Flare[b]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-805	Flare[b]	Spherical NGL Storage Tank	2011	865,200 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-2800	Flare[b]	Spherical NGL Storage Tank	2019	2,142,000 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-2801	Flare[b]	Spherical NGL Storage Tank	2019	865,200 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-2804	Flare[b]	Spherical NGL Storage Tank	2019	865,200 gal	Pressure Tank			Exempt		No controls, not atmospheric
US-2805	Flare[b]	Spherical NGL Storage Tank	2019	865,200 gal	Pressure Tank			Exempt		No controls, not atmospheric
N/A	N/A	Four (4) Pressurized NGL Bullet Tanks (V-1905, V-1915, V-1925, V-1935)	2014	90,000 gal (each)	Pressure Tank			Exempt		No controls, not atmospheric
N/A	N/A	Four (4) Pressurized NGL Bullet Tanks (V-2905, V-2915, V-2925, V-2935)	2019	90,000 gal (each)	Pressure Tank			Exempt		No controls, not atmospheric
TK-906	TK-906	Slop Tank	2011	21,000 gal	None			Exempt		No controls
TK-2906	TK-2906	Slop Tank	2019	21,000 gal	None			Exempt		No controls
TK-907	TK-907	Produced Water Tank	2012	63,000 gal	None			Exempt		No controls

Emission Unit ID	Emission Point ID	Emission Unit Description	Year installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	CAM status - Subject or Exempt	Pollutant	Reason for exemption
TK-2907	TK-2907	Produced Water Tank	2019	63,000 gal	None			Exempt		No controls
S011	P005	Ethane Amine Regenerator	2012	129 mmscfd	None - Still vent C004 - Flash tank			Exempt		Uncontrolled emissions < 100 tpy for VOC
S054	P054	Ethane Amine Regenerator	2019	129 mmscfd	VRU - Still vent C004 - Flash tank			Exempt		Uncontrolled emissions < 100 tpy for VOC
S008	P008	Product Loading (Truck, Rail, Propane Barge)	2011	3,600 gpm (truck) 4,000 gpm (rail) 4,000 gpm (barge)	VRU	Inherent	N/A	Exempt		Loading of pressurized products occurs via a vapor balanced system. Therefore, the VRU is inherent to the process.
S015	S015	Slop Water Truck Loading	2011	150 gpm	None			Exempt		No controls
S033	P033	Natural Gasoline Loading (Barge)	2017	4,000 gpm	None			Exempt		No controls
S055	P055	Pressurized NGL/Condensate Unloading	2012	3,600 gpm	None			Exempt		No controls
TK-L-1	TK-L-1	Gasoline Dispenser Tank	2017	20 gal/hr	None			Exempt		No controls
L-1	L-1	Gasoline Dispenser Loading	2017	20 gal/hr	None			Exempt		No controls
S002	P002	Caterpillar Model C18 Fire Pump #1 Diesel (Manufactured 2011)	2012	700 HP	None			Exempt		No controls
S003	P003	Caterpillar Model C18 Fire Pump #2 Diesel (Manufactured 2011)	2012	700 HP	None			Exempt		No controls
S058	P058	Fire Pump Engine(s)	2020	3,000 HP	None			Exempt		No controls
S034	P034	Propane Pigging (including Flare)	2017	N/A	Flare (C034)			Exempt		Uncontrolled emissions < 100 tpy for VOC
S035	P035	Pigging Operations	2017	N/A	VRU / None[c]			Exempt		Uncontrolled emissions <100 tpy for VOCs for 30" inlet receivers w/VRU and no controls for remaining launchers and receivers
FUG AREA 1	N/A	Fugitive Area 1	2011	N/A	None			Exempt		No controls
FUG AREA 2	N/A	Fugitive Area 2	2011	N/A	None			Exempt		No controls
FUG AREA 3	N/A	Fugitive Area 3	2018	N/A	None			Exempt		No controls
FUG AREA 4	N/A	Fugitive Area 4	2019	N/A	None			Exempt		No controls
FUG AREA 5	N/A	Fugitive Area 5	2019	N/A	None			Exempt		No controls
FUG AREA 6	N/A	Fugitive Area 6	2019	N/A	None			Exempt		No controls
FUG AREA 7	N/A	Fugitive Area 7	2019	N/A	None			Exempt		No controls
S010	N/A	Unpaved Roads	2011	N/A	None			Exempt		No controls

Emission Unit ID	Emission Point ID	Emission Unit Description	Year installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	CAM status - Subject or Exempt	Pollutant	Reason for exemption
S004A	P004A	Callidus CAL-MP Staged, Multi-Point Ground Flare System (C004A)	2015	19,800,000 scf/hr	N/A	No	Yes	Subject	VOC	N/A

[a] Tank uses a natural gas blanket to prevent emissions of natural gasoline. Working/breathing losses of natural gas blanket are collected and sent to Hot Oil Heater (S001) as a supplemental fuel.

[b] This tank is pressurized in excess of 204.9 kPa (which exempts the tank from applicability to 40 CFR 60, Subpart Kb) and normally has no emissions. In the case of emergency, emissions from the tank can be flared in C004A.

[c] The pigging vapors from the three truck side 30" Inlet receivers are captured by the VRU and routed back to the process.

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	Pollutant	CAM status - subject or exempt	Reason for exemption
TB1	TB1AE/BE	GE LM6000PG SPRINT / Siemens SGT-800 Combustion Turbine #1 and associated Duct Burner	2021	Scenario A: 482.6 mmBtu/hr Scenario B: 496.2 mmBtu/hr	OC1, SCR1	No	Yes	NOx	Subject	N/A
								CO		
								VOC	Exempt	Uncontrolled emissions < 100 tpy
TB2	TB2AE/BE	GE LM6000PG SPRINT / Siemens SGT-800 Combustion Turbine #2 and associated Duct Burner	2021	Scenario A: 482.6 mmBtu/hr Scenario B: 496.2 mmBtu/hr	OC2, SCR2	No	Yes	NOx	Subject	N/A
								CO		
								VOC	Exempt	Uncontrolled emissions < 100 tpy
TB3	TB3AE/BE	GE LM6000PG SPRINT / Siemens SGT-800 Combustion Turbine #3 and associated Duct Burner	2021	Scenario A: 482.6 mmBtu/hr Scenario B: 496.2 mmBtu/hr	OC3, SCR3	No	Yes	NOx	Subject	N/A
								CO		
								VOC	Exempt	Uncontrolled emissions < 100 tpy

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device	Inherent or Passive?	Control Device Used to Comply with Emission Limit?	Pollutant	CAM status - subject or exempt	Reason for exemption
TB4	TB4AE/BE	GE LM6000PG SPRINT / Siemens SGT-800 Combustion Turbine #4 and associated Duct Burner	2021	Scenario A: 482.6 mmBtu/hr Scenario B: 496.2 mmBtu/hr	OC4, SCR4	No	Yes	NOx	Subject	N/A
								CO		
								VOC	Exempt	Uncontrolled emissions < 100 tpy
FH1	FH1E	Fuel Gas Heater #1	2021	9.9 mmBtu	Low-NO_X burner	Passive			Exempt	Uncontrolled emissions < 100 tpy for NO_X
FH2	FH2E	Fuel Gas Heater #2	2021	9.9 mmBtu	Low-NO_X burner	Passive			Exempt	Uncontrolled emissions < 100 tpy for NO_X
EG1	EG1E	Emergency Generator	2021	1,676 hp	None				Exempt	No controls
FP1	FP1E	Emergency Fire Pump Engine	2021	700 hp	None				Exempt	No controls
OT1-4	OT1E-OT4E	Lubricating Oil Tank #1-4	2021	5,000 gal	None				Exempt	No controls
OT5-8	OT5E-OT8E	Waste Oil Tank #1-4	2021	250 gal	None				Exempt	No controls
AT1	AT1E	Ammonia/Urea Storage Tank	2021	60,000 gal	None				Exempt	No controls
WS1-4	WS1E-4E	Washout Sumps #1-4	2021	250 gal	None				Exempt	No controls
GT1-1	GT1E-4E	Glycol Tanks #1-4	2021	1,000 gal	None				Exempt	No controls
FT1	FT1E	Generator Fuel Tank	2021	25 gal	None				Exempt	No controls
FT2	FT2E	Fire Pump Engine Fuel Tank	2021	25 gal	None				Exempt	No controls
EL1	n/a	Equipment Leaks	2021	n/a	n/a				Exempt	No controls