

AIR POLLUTION CONTROL PERMIT TO CONSTRUCT

Pursuant to Chapter 23-25 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33-15 of the North Dakota Administrative Code), and in reliance on statements and representations heretofore made by the owner designated below, a Permit to Construct is hereby issued authorizing such owner to construct and initially operate the source unit(s) at the location designated below. This Permit to Construct is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Health and to any conditions specified below:

I. General Information:

A. **Permit to Construct Number:** PTC17020

B. **Source:**

1. **Name:** Davis Refinery
2. **Location:** Sec. 1 SW¹/₄ & Sec. 2 SE¹/₄, T139N, R100W
37th Street
Approximately 2 miles west of Belfield
Billings County, North Dakota
Lat: 46°52'45" N Long: 103°14'55" W
3. **Source Type:** Petroleum Refinery with a rated capacity of up to approximately 55,000 barrels of crude oil per day. The plant will produce refined products including gasoline, diesel fuel, jet fuel, as well as liquefied petroleum gas.
4. The construction of the Davis Refinery is scheduled to take place in two separate phases. This permit includes the emissions sources and limits from both project phases to ensure the facility will remain a minor source during both phases of operation.
5. **Equipment at the Facility:**

Process Unit	Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment or Design Features	Phase
Atmospheric Distillation Unit (ADU) Crude desalting and distillation unit with an estimated capacity of 2 x 27,500 bbl/day (55,000 bbl/day total)	ADU process equipment	1	Fugitive	Enhanced Leak Detection and Repair (ELDAR) Program Vapor Recovery Unit (VRU) system, excess emissions to flare (EU10), Design Requirements of New Source Performance Standards, Subpart NNN (NSPS NNN)	1

Process Unit	Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment or Design Features	Phase
	ADU Feed Heater #1 rated at 82.13 MMbtu/hr	1A	1A	Best Combustion Practices (BCP), Ultra Low-NO _x Burner (ULNB), and Selective Catalytic Reduction (SCR)	1
	ADU Feed Heater #2 rated at 82.13 MMbtu/hr	1B	1B	BCP, ULNB, SCR	2
	ADU sewers	1C	Fugitive	Design Requirements of New Source Performance Standards, Subpart QQQ (NSPS QQQ)	1
Vacuum Distillation Unit (VDU) ADU tower bottoms distillation unit with an estimated capacity of 16,800 bbl/day	VDU process equipment	2	Fugitive	ELDAR Program, NSPS NNN	2
	VDU Feed Heater rated at 75.00 MMbtu/hr	2A	2A	BCP, ULNB, SCR	2
	VDU sewers	2B	Fugitive	NSPS QQQ	2
Naphtha Hydrotreater Unit (NHT) with an estimated capacity of 18,205 bbl/day	NHT process equipment	3	Fugitive	ELDAR Program, NSPS NNN	1
	NHT Feed Heater rated at 8.60 MMbtu/hr	3A	3A	BCP, ULNB	1
	NHT Stabilizer Reboiler rated at 9.30 MMbtu/hr	3B	3B	BCP, ULNB	1
	NHT Splitter Reboiler rated at 17.90 MMbtu/hr	3C	3C	BCP, ULNB	1
	NHT sewers	3D	Fugitive	NSPS QQQ	1
Catalytic Reforming Unit (CRU) with an estimated capacity of 16,128 bbl/day Hydrogen (H ₂) production from CRU is between 4-19 MMscf/day	CRU process equipment	4	Fugitive	ELDAR Program, NSPS NNN	1
	CRU Reactor #1 Heater rated at 45.63 MMbtu/hr	4A	4 ^A	BCP, ULNB, SCR	1
	CRU Reactor #2 Heater rated at 45.63 MMbtu/hr	4B		BCP, ULNB, SCR	1
	CRU Reactor #3 Heater rated at 45.63 MMbtu/hr	4C		BCP, ULNB, SCR	1
	CRU Stabilizer Reboiler rated at 5.70 MMbtu/hr	4D	4D	BCP, ULNB	1
	CRU Regenerator Vent	4E	4E	Wash Drum	1
	CRU sewers	4F	Fugitive	NSPS QQQ	1
Distillates Hydrotreater Unit (DHT) with an estimated capacity of 19,850 bbl/day	DHT process equipment	5	Fugitive	ELDAR Program, NSPS NNN	1
	DHT Feed Heater rated at 19.50 MMbtu/hr	5A	5A	BCP, ULNB	1

Process Unit	Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment or Design Features	Phase
	DHT Splitter Reboiler rated at 27.30 MMBtu/hr	5B	5B	BCP, ULNB	2
	DHT sewers	5C	Fugitive	NSPS QQQ	1
Hydrocracker Unit (HYK) with an estimated capacity of 14,380 bbl/day	HYK process equipment	6	Fugitive	ELDAR Program, NSPS NNN	2
	HYK Reactor Heater rated at 37.16 MMBtu/hr	6A	6A	BCP, ULNB, SCR	2
	HYK Fractionator Heater rated at 40.34 MMBtu/hr	6B	6B	BCP, ULNB, SCR	2
	HYK sewers	6C	Fugitive	NSPS QQQ	2
Sulfur Recovery Unit ^B (SRU) with an estimated capacity of 11.5 tpd sulfur production	SRU process equipment	7	Fugitive	ELDAR Program	1
	Thermal Oxidizer with a rated capacity of 1.58 MMBtu/hr	7A	7A	Thermal Oxidizer NSPS Ja	1
	SRU sewers	7B	Fugitive	NSPS QQQ	1
Boilerhouse	Process equipment	8	Fugitive	ELDAR Program	1
	Medium Pressure Steam Boiler #1 rated at 11.68 MMBtu/hr	8A	8 ^C	BCP, ULNB	1
	Medium Pressure Steam Boiler #2 rated at 11.68 MMBtu/hr	8B		BCP, ULNB	1
	Medium Pressure Steam Boiler #3 rated at 11.68 MMBtu/hr	8C		BCP, ULNB	1
	Medium Pressure Steam Boiler #4 rated at 11.68 MMBtu/hr	8D		BCP, ULNB	2
	High Pressure Steam Boiler #1 rated at 22.00 MMBtu/hr	8E	8E ^D	BCP, ULNB	2
	High Pressure Steam Boiler #2 rated at 22.00 MMBtu/hr	8F	8F ^D	BCP, ULNB	2
	High Pressure Steam Boiler #3 rated at 22.00 MMBtu/hr	8G	8G ^D	BCP, ULNB	2
	Oil Movements	Process equipment	9	Fugitive	ELDAR Program
Storage Tank Farm		9A	Various	See Condition I.B.6 Table	1
Oil Movements		9B	Fugitive	NSPS QQQ	1

Process Unit	Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment or Design Features	Phase
Flare System	Enclosed hydrocarbon (HC) operating flare rated to handle up to 24.4 MMscf/day (including purge and fuel gas blowdown)	10	10	NSPS Ja, VRU control, Smokeless Operation	1
	Acid gas flare rated to handle up to 15.8 MMscf/day	10A	10A	SRU ^E , NSPS Ja compliant, Smokeless Operation	1
	HC secondary flare #1 rated to handle up to 74.6 MMscf/day	10B	10B	NSPS Ja, VRU control, Smokeless Operation	1
	HC secondary flare #2 rated to handle up to 88.8 MMscf/day	10C	10C	NSPS Ja, VRU control, Smokeless Operation	2
Loading/Unloading System	Process Equipment	11	Fugitive	ELDAR Program	1
	Truck loading rack VRU system	11A	11A	Submerged loading, VRU, MACT BBBBBB (6B)	1
Wastewater Treatment Plant (WWTP)	Oil/Separator inlet from Benzene Waste Operators NESHAP (BWON) compliant plant	12	Fugitive	NSPS QQQ, NESHAP FF	1
Cooling Tower (CT) five cell induced draft counter flow system with a water circulation rate of 2,500 gal/min for each cell.	CT cell #1	13 ^F	13A	Drift Eliminators (0.001% maximum drift) inherent to design	1
	CT cell #2		13B		1
	CT cell #3		13C		2
	CT cell #4		13D		2
	CT cell #5		13E		2
Emergency Units	Three Diesel Engine Power Generators each rated at 4,700 BHP	14A	14A	NSPS IIII ^G	1
		14B	14B		
		14C	14C		
	Three Back-up Diesel Engine Firewater Pumps each rated at 600 BHP	15A	15A	NSPS IIII ^G	1
		15B	15B		
		15C	15C		

- A Common flue stack.
- B Merichem LO-CAT® technology, reduction control.
- C Common flue stack. Under normal operations, during Phase 1, two will be in service and one on stand-by, during Phase 2, three will be in service and one on stand-by.
- D Under normal operations, two will be in service and one on stand-by.
- E Under normal operations, the acid gas flow is routed to the SRU.
- F Under normal operations, during Phase 1, one will be in service and one on stand-by. During Phase 2, four will be in service and one on stand-by.
- G The engines shall be certified to emissions standards as outlined under 40 CFR 60, Subpart IIII. The engines shall be manufactured and installed with the appropriate control equipment to meet these emissions standards.

6. Storage Tanks:

Storage Area	Tank Number	Nominal Capacity (bbl)	Material Stored	Tank Type/Controls
Feedstock	301	110,999	Crude oil	Internal Floating Roof (IFR), Submerged Fill Pipe (SFP)
	302	110,999	Crude oil	IFR, SFP
Intermediate Products	305	64,996	Desulfurized heavy naphtha	IFR, SFP
	313	33,312	Distillates (Kerosene and Diesel)	Fixed Roof (FR), SFP
	327	2,620	Light slop	IFR, SFP
	328	2,620	Heavy slop	FR, SFP
	323	33,312	Vacuum gas oil / Fuel Oil	FR, SFP
Blend stocks	306	33,312	Reformate	IFR, SFP
	307	33,312	Reformate	IFR, SFP
	331	33,312	Hydrotreated light naphtha	IFR, SFP
	332	33,312	Hydrotreated light naphtha	IFR, SFP
Final Products	P301 ^A	60,000 gallons	Butane	Bullet tank (pressure tank)
	P302 ^A	60,000 gallons	Butane	Bullet tank (pressure tank)
	P303 ^A	60,000 gallons	Butane	Bullet tank (pressure tank)
	P304 ^A	60,000 gallons	Propane grade LPG	Bullet tank (pressure tank)
	P305 ^A	60,000 gallons	Propane grade LPG	Bullet tank (pressure tank)
	P306 ^A	60,000 gallons	Propane grade LPG	Bullet tank (pressure tank)
	308	64,996	Tier 3 regular gasoline	IFR, SFP
	309	64,996	Tier 3 regular gasoline	IFR, SFP
	311	33,312	Jet-Fuel	IFR, SFP
	312	33,312	Jet-Fuel	IFR, SFP
	315	64,996	Ultra low sulfur diesel (ULSD)	FR, SFP
	316	64,996	ULSD	FR, SFP
	324	33,312	Low sulfur fuel oil	FR, SFP

^A Insignificant emissions units.

C. **Owner/Operator (Permit Applicant):**

1. Name: Meridian Energy Group, Inc.
2. Address: 37th Street
Belfield, ND 58622
3. Application Date: October 6, 2016 (original)
April 5, 2017 (amendment and supplemental information thereafter)

II. **Conditions:** This Permit to Construct allows the construction and initial operation of the above-mentioned new or modified equipment at the source. The source may be operated under this Permit to Construct until a Permit to Operate is issued unless this permit is suspended or revoked. The source is

subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below.

- A. **Emission Limits:** Emission limits from the operation of the source unit(s) identified in Item I.B of this Permit to Construct (hereafter referred to as "permit") are as follows. Source units not listed are subject to the applicable emission limits specified in the North Dakota Air Pollution Control Rules.

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
ADU process equipment	1	Fugitive	VOC	ELDAR NSPS NNN	10 16
ADU Feed Heater #1 rated heat input of 82.13 MMbtu/hr	1A	1A	NO _x	0.0063 lb/MMbtu (6 ppmvd @ 0% O ₂)	3.a
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
ADU Feed Heater #2 rated heat input of 82.13 MMbtu/hr	1B	1B	NO _x	0.0063 lb/MMbtu (6 ppmvd @ 0% O ₂)	3.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
ADU sewers	1C	Fugitive	VOC	NSPS QQQ	11
VDU process equipment	2	Fugitive	VOC	ELDAR NSPS NNN	10 16

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
VDU Feed Heater rated at 75.00 MMBtu/hr	2A	2A	NO _x	0.0063 lb/MMbtu (6 ppmvd @ 0% O ₂)	3.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
VDU sewers	2B	Fugitive	VOC	NSPS QQQ	11
NHT process equipment	3	Fugitive	VOC	ELDAR NSPS NNN	10 16
NHT Feed Heater rated 8.60 MMbtu/hr	3A	3A	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO (Phase 1)	0.0380 lb/MMbtu (60 ppmvd @ 0% O ₂)	5.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
NHT Stabilizer Reboiler rated 9.30 MMBtu/hr	3B	3B	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO (Phase 1)	0.0380 lb/MMbtu (60 ppmvd @ 0% O ₂)	5.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
NHT Splitter Reboiler rated at 17.90 MMbtu/hr	3C	3C	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO (Phase 1)	0.0380 lb/MMbtu (60 ppmvd @ 0% O ₂)	5.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
NHT sewers	3D	Fugitive	VOC	NSPS QQQ	11
CRU process equipment	4	Fugitive	VOC	ELDAR	10
CRU Reactor #1 Heater rated at 45.63 MMbtu/hr)	4A	4	NO _x	0.0063 lb/MMbtu (6 ppmvd @ 0% O ₂)	3.a
CRU Reactor #2 Heater rated at 45.63 MMbtu/hr	4B		CO (Phase 1)	0.0380 lb/MMbtu (60 ppmvd @ 0% O ₂)	5.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
CRU Reactor #3 Heater rated at 45.63 MMbtu/hr	4C		H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
CRU Stabilizer Reboiler rated at 5.70 MMbtu/hr	4D	4D	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO (Phase 1)	0.0380 lb/MMbtu (60 ppmvd @ 0% O ₂)	5.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
CRU Regenerator Vent	4E	4E	Opacity	20%	Condition II.E.10
CRU sewers	4F	Fugitive	VOC	NSPS QQQ	11
DHT process equipment	5	Fugitive	VOC	ELDAR NSPS NNN	10 16
DHT Feed Heater rated at 19.50 MMbtu/hr	5A	5A	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO (Phase 1)	0.0380 lb/MMbtu (60 ppmvd @ 0% O ₂)	5.a
			CO (Phase 2)	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
DHT Splitter Reboiler rated at 27.30 MMbtu/hr	5B	5B	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
DHT sewers	5C	Fugitive	VOC	NSPS QQQ	11
HYK process equipment	6	Fugitive	VOC	ELDAR NSPS NNN	10 16
HYK Reactor Heater rated at 37.16 MMbtu/hr	6A	6A	NO _x	0.0063 lb/MMbtu (6 ppmvd @ 0% O ₂)	3.a
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
HYK Fractionator Heater rated at 40.34 MMbtu/hr	6B	6B	NO _x	0.0063 lb/MMbtu (6 ppmvd @ 0% O ₂)	3.a
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
HYK sewers	6C	Fugitive	VOC	NSPS QQQ	11
SRU process equipment	7	Fugitive	VOC	ELDAR	10
Thermal Oxidizer with a rated capacity of 1.58 MMbtu/hr	7A	7A	SO ₂	2,500 ppm SO ₂	2, 8
			Opacity	5%	7
SRU sewers	7B	Fugitive	VOC	NSPS QQQ	11
Process equipment	8	Fugitive	VOC	ELDAR	10
Medium Pressure Steam Boiler #1 rated at 11.68 MMbtu/hr	8A	8	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
Medium Pressure Steam Boiler #2 rated at 11.68 MMbtu/hr	8B		CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
Medium Pressure Steam Boiler #3 rated at 11.68 MMbtu/hr	8C		H ₂ S	Pipeline Quality Natural Gas	4.b, 17
Medium Pressure Steam Boiler #4 rated at 11.68 MMbtu/hr	8D		PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
High Pressure Steam Boiler #1 rated at 22.00 MMbtu/hr	8E	8E	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a, 17
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
High Pressure Steam Boiler #2 rated at 22.00 MMbtu/hr	8F	8F	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a, 17
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
High Pressure Steam Boiler #3 rated at 22.00 MMbtu/hr	8G	8G	NO _x	0.0300 lb/MMbtu (29 ppmvd @ 0% O ₂)	3.b
			CO	0.0280 lb/MMbtu (44 ppmvd @ 0% O ₂)	5.b
			H ₂ S	15 ppmv H ₂ S in fuel gas ^A	4.a, 17
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	0.0040 lb/MMbtu	6
			Opacity	5%	7
Process equipment	9	Fugitive	VOC	ELDAR	10
Storage Tank Farm	9A	301	VOC	MACT WW	12.a
		302	VOC	MACT WW	12.a
		305	VOC	MACT WW	12.a
		313	VOC	NSPS Kb	12.b
		327	VOC	MACT WW	12.a
		328	VOC	MACT WW	12.a
		323	VOC	NSPS Kb	12.b
306	VOC	MACT 6B via MACT WW	12.a		

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
		307	VOC	MACT 6B via MACT WW	12.a
		331	VOC	MACT 6B via MACT WW	12.a
		332	VOC	MACT 6B via MACT WW	12.a
		308	VOC	MACT 6B via MACT WW	12.a
		309	VOC	MACT 6B via MACT WW	12.a
		311	VOC	MACT WW	12.a
		312	VOC	MACT WW	12.a
		315	VOC	NSPS Kb	12.b
		316	VOC	NSPS Kb	12.b
		324	VOC	NSPS Kb	12.b
Oil Movements	9B	Fugitive	VOC	NSPS QQQ	11
Enclosed hydrocarbon (HC) operating flare rated to handle up to 24.4 MMscf/day (including purge and fuel gas blowdown)	10	10	VOC	NSPS Ja – flare header connected to VRU	2, 9
			Opacity	NSPS A	9.f
Acid gas flare rated to handle up to 15.8 MMscf/day	10A	10A	VOC	Routed to SRU under normal operations,	2, 9
			H ₂ S/TRS	NSPS Ja – flare header	9.d
			Opacity	NSPS A	9.f
HC secondary flare #1 rated to handle up to 74.6 MMscf/day of emergency relief	10B	10B	VOC	NSPS Ja – secondary flare with water seal	2, 9, 9.c
			Opacity	NSPS A	9.f
HC secondary flare #2 rated to handle up to 88.8 MMscf/day of emergency relief	10C	10C	VOC	NSPS Ja – secondary flare with water seal	2, 9, 9.c
			Opacity	NSPS A	9.f
Process Equipment	11	Fugitive	VOC	ELDAR	10
Truck loading rack	11A	11A	VOC	ELDAR MACT Subpart 6B	10 13
Oil/Separator inlet from Benzene Waste Operators NESHAP (BWON) compliant plant	12	Fugitive	VOC	NSPS QQQ	11
			Total Annual Benzene (TAB)	NESHAP FF	14
CT cell #1	13	13A	No Chromium Compounds	NESHAP Q	15
CT cell #2		13B			
CT cell #3		13C			
CT cell #4		13D			
CT cell #5		13E			

Emission Unit	EU	EP	Pollutant/ Parameter	Emission Limit or Design / Work Practice	Reference Condition II.A
Three Diesel Engine Power Generators each rated at 4700 BHP	14A	14A	NO _x + NMHC	4.8 g/bhp-hr	18.a.i
	14B	14B	PM	0.15 g/bhp-hr	18.a.ii
	14C	14C	Opacity	20%	18.a.iii
Three Back-up Diesel Engine Firewater Pumps each rated at 600 BHP	15A	15A	NO _x + NMHC	3.0 g/bhp-hr	18.b.i
	15B	15B	PM	0.15 g/bhp-hr	18.b.ii
	15C	15C	PM	0.15 g/bhp-hr	18.b.ii
Total Volatile Organic Compounds (VOC) from EUs: 1, 1A, 1B, 1C, 2, 2A, 2B, 3, 3A, 3B, 3C, 3D, 4, 4A, 4B, 4C, 4D, 4F, 5, 5A, 5B, 5C, 6, 6A, 6B, 6C, 7, 8, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 9, 9A, 9B, 10, 10A, 10B, 10C, 11, 11A, 12, 13, 14A-C, 15A- C			VOC	58 tons/year (12-month rolling sum) ^B	Condition II.D.1
Total Carbon Monoxide (CO) from EUs: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C			CO	80 tons/year (12-month rolling sum) ^B	Condition II.D.2
Total Nitrogen Oxides (NO _x) from EUs: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C			NO _x	40 tons/year (12-month rolling sum) ^B	Condition II.D.3
Total Sulfur Dioxide (SO ₂) from EUs: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C			SO ₂ (RFG H ₂ S content used for SO ₂ from combustion)	13 tons/year (12-month rolling sum) ^B	Condition II.D.4

^A The permittee shall monitor H₂S at a single point using a continuous monitor system (CMS) located at the fuel gas distribution header.

^B The emission limit applies to the combined emissions from all listed emission units.

1. **Best Management Practices:**

At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

2. **40 CFR 60, Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007**

All fuel gas combustion devices (FGCD), flares, and the sulfur recovery unit at the facility are subject to the design, equipment, and work practice or operational standards of new source performance standards (NSPS) Subpart Ja, specifically, 40 CFR (§)60.103a.

Root Cause Analysis and Corrective Action Analysis: Each FGCD, flare, and sulfur recovery plant shall conduct a root cause analysis and corrective action analysis for each of the conditions specified in §60.103a(c)(1) through (c)(3). The root cause analysis and corrective action analysis must be completed by the schedule provided in §60.103a(d) and shall implement the corrective actions in accordance with §60.103a(e).

3. FGCD Nitrogen Oxide (NO_x) Emissions:

The permittee has elected to comply with NO_x emission limits which are more stringent than NSPS Ja. The following emissions limits are applicable to the FGCD, based on the control technology:

- a. Ultra-Low NO_x Burners (ULNB) with Selective Catalytic Reduction (SCR): For EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B. The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain NO_x in excess of 0.0063 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 6 ppmvd, corrected to 0% excess O₂).
- b. ULNB: For EUs 3A, 3B, 3C, 4D, 5A, 5B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G. The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain NO_x in excess of 0.0300 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 29 ppmvd, corrected to 0% excess O₂).

4. Fuel Gas Combustion Sulfur Dioxide (SO₂) Emissions:

The permittee has elected to comply with SO₂ emission limits which are more stringent than NSPS Ja. The permittee shall use a continuous monitor system (CMS) to monitor the H₂S concentration from the refinery fuel gas (RFG) system to determine SO₂ emissions from each FGCD which burns RFG. The permittee has elected to install the CMS on the RFG system header exiting the SRU that is common to all the FGC units to comply with §60.102a(2)(i). The following limits apply, based on the fuel burned:

- a. The process heaters and high pressure boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8E, 8F, and 8G) shall not burn refinery fuel gas that contains H₂S in excess of 15 ppmv determined daily on a 30-day rolling average basis.
- b. The Medium Pressure Boilers (EUs 8A, 8B, 8C, and 8D) and Flare System (EU 10, 10A, 10B, and 10C) pilots shall be fired on pipeline quality natural gas containing no more than 2 grains of H₂S per 100 standard cubic feet.

5. Fuel Gas Combustion Carbon Monoxide (CO) Emissions:

Best Combustion Practices (BCP) for all process heaters and boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G). The permittee shall comply with the following limits:

- a. During Phase 1, shall not discharge or cause the discharge of any gases into the atmosphere that contain CO in excess of 0.0380 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 60 ppmvd, corrected to 0% excess O₂).
- b. During Phase 2, shall not discharge or cause the discharge of any gases into the atmosphere that contain CO in excess of 0.0280 lb/MMbtu determined daily on a 30-day rolling average basis (equivalent to no greater than 44 ppmvd, corrected to 0% excess O₂).

6. **Fuel Gas Combustion Particulate Matter <10 microns (PM₁₀) and PM <2.5 microns (PM_{2.5}) Emissions:**

Combined filterable and condensable fractions. For all process heaters and boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G), the permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain PM₁₀ and/or PM_{2.5} in excess of 0.0040 lb/MMbtu calculated as the average of three valid 1-hour test runs.

7. **Fuel Gas Combustion Opacity:**

For all process heaters and boilers (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G), the permittee shall comply with the opacity limit of 5% except for one six-minute period per hour when 10% opacity is permissible.

8. **Sulfur Recovery Unit (SRU) SO₂ Emissions:**

The SRU (EU 7) is classified as a sulfur recovery plant with a capacity of less than 20 long tons per day with a reduction control system followed by incineration. Thermal Oxidizer (EU 7A; EP 7A) is the incinerator following the SRU and is the only point source of emissions in the process area.

The permittee shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume of SO₂ (dry basis) at zero percent excess air, on a 12-hour rolling average basis to comply with §60.102a(f)(2)(i).

9. **Flare Operation:**

The permittee has elected to construct and operate the refinery with a cascaded flare system. This system will be equipped with a flare gas recovery system designed, sized and

operated to capture all flows except those resulting from startup, shutdown or malfunction. HC Operating Flare (EU 10) will be the first flare downstream of the flare gas recovery system. HC Secondary Flare #1 (EU 10B), HC Secondary Flare #2 (EU 10C) will be secondary flares fitted with water seals downstream of EU 10. In addition, the permittee has elected to manage process upset gases released to the flare system as a result of emergency malfunctions from the sour water unit and/or sulfur recovery unit through a separate Acid Gas Flare (EU 10A).

The permittee shall comply with the following:

- a. The blowdown and flare system shall be designed and operated in accordance with the requirements of North Dakota Administrative Code (NDAC) 33-15-12-02, Subpart A, 60.18 (§60.18). The flare shall be operated with a flame present at all times when emissions may be vented to the flare.
- b. The flare system is subject to the H₂S limitations of §60.103a(h). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this the limit requirements of §60.103a(h).
- c. The cascaded flare system, including EU 10, EU 10B and EU 10C shall comply with the emission monitoring provisions of 40 CFR 60.107a(g).
- d. The acid flare EU 10A shall comply with the applicable emission monitoring provisions of §60.107a(e) and (f).
- e. The permittee shall develop and implement a written flare management plan no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in §60.103a(a)(2) and/or the procedures in §60.103a(a)(5) through (a)(7) that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The plan must include the information described in §60.103a(a)(1) through (a)(7).
- f. Flare Visible Emissions: Flares shall be operated with no visible emissions except for periods not to exceed a total of five minutes during any two consecutive hours. Reference Method 22 of 40 CFR 60, Appendix A shall be used to determine compliance with this visible emissions provision.

10. Enhanced Leak Detection & Repair (ELDAR) Program:

The permittee is subject to 40 CFR 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (NSPS GGGa). NSPS GGGa references 40 CFR 60, Subpart VVa – Standards of Performance for

Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (NSPS VVa) for the standards of compliance.

As allowed under NSPS VVa¹, the permittee has elected to comply with the requirements of 40 CFR 63, Subpart H – National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks (MACT H).

For all equipment in VOC service, as defined in §60.481a, located at EUs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 11A, the permittee shall comply with the following standards:

- a. General. The Permittee shall comply with the general standards under §63.162.
- b. Pumps in light liquid service. Each pump in light liquid service shall be equipped with a dual mechanical seal that includes a barrier fluid system meeting the requirements of §63.163(e).
- c. Compressors. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of process fluid to the atmosphere and meets the requirements of §63.164(b) – (e).
- d. Pressure relief devices in gas/vapor service. All pressure relief devices in gas/vapor service shall meet the requirements of §63.165(a) – (d). Pressure relief devices that are connected to the flare gas header are exempt (§63.172(b)).
- e. Sampling connection systems. All sampling connection systems shall meet the requirements of §63.166(a) – (c).
- f. Open-ended valves or lines. All open-ended valves and lines shall meet the requirements of §63.167(a) – (e).
- g. Valves in gas/vapor service and in light liquid service. All valves in gas/vapor and light liquid service shall meet the requirements of §63.168(a) – (h).
- h. Pumps, valves, connectors, and agitators in heavy liquid service; instrument systems; and pressure relief devices in liquid service. All Pumps, valves, connectors, and agitators shall meet the requirements §63.169(a) – (d).
- i. Surge control vessel and bottoms receivers. Each surge control vessel and bottom receiver shall meet the requirements of §63.172(a) – (n).

¹ 40 CFR 60, Subpart VVa. §60.480a(e)(2)(i) “Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §60.482-1a through §60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of §60.485a(d), (e), and (f), and §60.486a(i) and (j) still apply.”

- j. Closed-vent systems and control devices. Each closed-vent systems and control devices shall meet the requirements of §63.172(a) – (n).
- k. Agitators in gas/vapor service and in light liquid service. Each agitator in gas/vapor and light liquid service shall meet the requirements of §63.173(a) – (j).
- l. Connectors in gas/vapor service and in light liquid service. Each connector in gas/vapor service and light liquid service shall meet the requirements of §63.174(a) – (j).
- m. Delay of Repair. The Permittee shall comply with the delay of repair (DOR) requirements under §63.171.

The permittee shall meet emission reductions equivalent to the Texas Commission on Environmental Quality (TCEQ) 28LAER program².

Additionally, the permittee shall implement the ELDAR program for equipment with a screening rate of 500 parts per million by volume (ppmv), except for compressors (10,000 ppmv), summarized as follows:

Equipment/Service		TCEQ 28LAER Control Efficiency	Leak Threshold (ppmv)
Valves	Gas/Vapor	97%	500
	Light Liquid	97%	500
	Heavy Liquid	0%	500
Pumps	Light Liquid	85%	500
	Heavy Liquid	85%	500
Flanges/ Connectors	Gas/Vapor	97%	500
	Light Liquid	97%	500
	Heavy Liquid	30%	500
Compressors		85%	10,000
Relief Valves (Gas/Vapor)		97%	500
Sampling Connections		97%	500

The use of Alternative Work Practice (AWP) monitoring, such as optical gas imaging (OGI) in conjunction with approved Method 21 analyzers or other AWP as approved by the Department, shall be used to improve the efficiency of the ELDAR program. The permittee shall conduct AWP monitoring using OGI with Method 21 analyzers at least every 60 days.

² Attachment 1 <https://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/fugitives/nsr_fac_eqfug.html>

11. **40 CFR 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (NSPS QQQ)**

For all individual drain systems, oily water separators, and closed vent systems in the petroleum refinery wastewater system, as defined in §60.691, located at EUs 1C, 2B, 3D, 4F, 5C, 6C, 7B, 9B, and 12, the permittee shall comply with the following standards:

a. **Individual Drain Systems**

The individual drain systems requirements apply to the drains, junction boxes, and sewer lines which are part of the refinery process wastewater system.

- i. Each drain shall be equipped with water seal controls.
- ii. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 3 feet (90 cm) in length and shall not exceed 4 inches (10.2 cm) in diameter. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.
- iii. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

b. **Oily Water Separator (OWS)**

- i. Each oily water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the specifications in §60.692-3 (a), (b), (e), and (f), as applicable.
- ii. Storage vessels subject to 40 CFR 60, Subpart Kb (§60.112b) are not subject to the requirements of this subpart.
- iii. Oily wastewater resulting from tank draws shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system as indicated in §60.692-4(e).

c. **Closed Vent System**

- i. Each closed vent system, vapor recovery system, and/or flare shall comply with the requirements of §60.692-5(b) – (e).

d. **Exempt facilities and delay of repair**

An owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that the following facilities meet the exemption requirements of NSPS QQQ.

- i. Stormwater sewer system, which no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.
- ii. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily water.
- iii. Non-contact cooling water system, which demonstrates that the cooling water does not contact hydrocarbons or oily wastewater and is not recirculated through a cooling tower.
- iv. Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

12. Volatile Organic Liquids (VOL) Storage Tanks

- a. All internal floating roof tanks (IFRT) at the facility are subject to 40 CFR 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 (NSPS Kb).

NSPS Kb gasoline storage tanks are subject to the storage tank requirements of 40 CFR 63, Subpart BBBBBB – National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (MACT 6B) depending on the material stored in the tank.

As allowed^{3,4} for IFR tanks, the permittee has elected to comply with the more stringent requirements of 40 CFR 63, Subpart WW – National Emission Standards for Storage Vessels (Tanks) – Control Level 2 (MACT WW) and shall comply with floating roof requirements, specifically §63.1063(a) – (b).

³ 40 CFR 63, Subpart BBBBBB. Table 1, 2.(d) “Equip and operate each internal floating roof gasoline storage tank according to the applicable requirements in §63.1063(a)(1) and (b), except for the secondary seal requirements under §63.1063(a)(1)(i)(C) and (D)”

⁴ 40 CFR 63, Subpart CC. §63.640(n) “Overlap of this subpart with other regulations for storage vessels.” allows sources subject to both NSPS Kb and MACT CC to comply with only one of the subparts. Subsequently, §63.660 states “the owner or operator of a Group 1 storage vessel that is part of a new or existing source shall comply with the requirements in subpart WW of this part according to the requirements in paragraphs (a) through (i) of this section”

Applicable to tanks: 301, 302, 305, 306, 307, 308, 309, 311, 312, 327, 328, 331, and 332.

- b. The fixed roof tanks (FRT) are not subject to the design standards of NSPS Kb.

Applicable to tanks: 313, 315, 316, 324, and 325.

- c. All tanks shall be equipped with and filled through a submerged fill pipe to comply with NDAC Section 33-15-07-01.3.

13. **40 CFR 63 Subpart BBBBBB – National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (MACT 6B):**

The truck loading rack (EU 11 and 11A) is subject to MACT 6B and shall be operated with a submerged filling arm and Vapor Recovery Unit (VRU) at all times when gasoline loading operations are occurring. The permittee shall comply with the following:

- a. Load gasoline only in vapor tight cargo tanks that have been tested with the frequency and by the methods specified in 40 CFR 63.425 to assure vapor tightness.
- b. Product throughput records shall be submitted annually. Records shall be maintained for a minimum of three years.
- c. ELDAR and/or Olfactory, Visual and Audible (OVA) observations shall be conducted at a minimum every 30-days.
- d. NSPS Kb storage tanks shall comply with the conditions of MACT 6B.

14. **40 CFR 61 Subpart FF – National Emission Standard for Benzene Waste Operations (BWON):**

The Wastewater Treatment Plant (EU 12) and individual drain lines that convey process waste water to the oily water treatment system are subject to the BWON provisions. The provisions of this subpart apply to individual drain systems used to convey process wastewater from a process unit, product storage tank, or waste management unit to a waste management unit. Individual drain systems include all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving wastewater treatment system. Waste that is contained in a segregated stormwater sewer system and any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, are exempt from compliance with the provisions of this subpart.

15. **Five Cell Cooling Tower:**

For the Cooling Tower (EU 13), the permittee shall comply with the following:

- a. The cooling towers shall be equipped with and operated with mist eliminators that are guaranteed to limit drift to 0.001% or less of the circulating flow.
- b. Per 40 CFR 63 Subpart Q, the permittee shall not use chromium based water treatment chemicals in the cooling towers.

16. **40 CFR 60 Subpart NNN – Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (NSPS NNN):**

The process units at the Davis Refinery associated with the generation of LPG, light naphtha and gasoline range compounds as a product, co-product, by-product, or intermediate include the ADUs (EU 1) and VDU (EU 2), NHT (EU 3), CRU (EU 4), Benzene Saturation Unit and HYK (EU 6). As such, these units are subject to Subpart NNN.

As allowed by this subpart, the permittee has chosen to install a vapor recovery system designed, sized, and operated to capture all flows discharged through the vent streams of the above mentioned units except those resulting from startup, shutdown or malfunction. To comply with the standards of §60.662, the permittee will combust in a flare the emissions in excess of the VRU capacity.

17. **40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (NSPS Dc):**

The Medium Pressure Boilers (EUs 8A – 8D) and High Pressure Boilers (EU 8E – 8G), EUs 8A to 8G, are subject to the applicable reporting and recordkeeping requirements of NSPS Dc. The permittee has elected to run the Medium Pressure Boilers exclusively on pipeline quality natural gas, while the high pressure boilers will be run on refinery fuel gas. Permittee shall maintain records of the type and amount of fuel used by the boilers on a daily basis to comply with §60.48c(g)(1).

18. **40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS IIII):**

- a. Emergency diesel generators (EUs 14A-14C), 4,700 bhp each, are subject to the provisions of §60.4202(b)(2), which references §89.112 and §89.113, as follows:
 - i. NMHC (non-methane hydrocarbons) + NO_x limit: 4.8 g/bhp-hr (6.4g/kW-hr)

- ii. PM limit: 0.15 g/bhp-hr (0.20 g/kW-hr)
 - iii. Opacity limit: 20% during acceleration, 15% during lugging, and 50% during peaks in acceleration or lugging
- b. Emergency diesel fire pump engines (EUs 15A-15C), 600 bhp each, are subject to the provisions of §60.4205(c) and shall comply with the emissions standards in Table 4 to Subpart IIII, as follows:
- i. NMHC + NO_x limit: 3.0 g/bhp-hr
 - ii. PM limit: 0.15 g/bhp-hr

B. Emissions Testing:

1. **Initial Testing:** Within 60 days after achieving the maximum production rate at the plant, but not later than 180 days after startup, the permittee shall conduct emissions tests following the Methodology in 40 CFR 60, Appendix A, for the contaminants listed below:

Note: FGCDs subject to both a Phase 1 and Phase 2 CO emissions limit will be required to demonstrate compliance with applicable limits (i.e. Phase 1 CO compliance testing after Phase 1, and Phase 2 CO compliance testing after Phase 2).

Emissions Testing

Process Unit	EP	Contaminant
ADU Feed Heater #1	1A	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
ADU Feed Heater #2	1B	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
VDU Feed Heater	2A	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
NHT Feed Heater	3A	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
NHT Stabilizer Reboiler	3B	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A

Process Unit	EP	Contaminant
NHT Splitter Reboiler	3C	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
CRU Reactor #1/2/3 Heater	4	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
CRU Stabilizer Reboiler	4D	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
CRU Regenerator Vent	4E	Opacity ^E
DHT Feed Heater	5A	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
DHT Splitter Reboiler	5B	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
HYK Reactor Heater	6A	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
HYK Fractionator Heater	6B	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
Thermal Oxidizer	7A	SO ₂
Medium Pressure Steam Boiler #1/2/3/4	8	NO _x CO SO ₂ ^C PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
High Pressure Steam Boiler #1	8E	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
High Pressure Steam Boiler #2	8F	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
High Pressure Steam Boiler #3	8G	NO _x CO H ₂ S in fuel gas ^B PM ₁₀ & PM _{2.5} (Filterable + Condensable) ^A
Enclosed hydrocarbon (HC)	10	^D
Acid gas flare	10A	^D
HC secondary flare #1	10B	^D
HC secondary flare #2	10C	^D

Process Unit	EP	Contaminant
Diesel Engine Power Generator	14A-C	NO _x NMHC PM
Back-up Diesel Engine Firewater Pump	15 A-C	NO _x NMHC PM

- A Testing must follow EPA Method 201A and 202; these are not contained in 40 CFR 60, Appendix A.
- B Testing must either be conducted to measure the SO₂ emission rate or the H₂S concentration of the fuel gas. The permittee shall comply with all applicable requirements of 40 CFR 60.104a.
- C In lieu of 40 CFR 60 Appendix A compliance, permittee shall provide certification of pipeline quality natural gas sulfur content.
- D Flare units are not subject to initial performance testing as they are not intended to operate on a routine basis, only in upset conditions. Flare unit compliance will be based on CEMS relative accuracy testing and certification of pipeline quality natural gas sulfur content for the operations of the pilot units.
- E Reference Method 9 test required for initial compliance demonstration.
2. **Notification:** The permittee shall notify the Department using the form in the Emission Testing Guideline, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department at least five days prior to the scheduled test date and coordinate a new test date with the Department.
3. **Sampling Ports/Access:** Sampling ports shall be provided downstream of all emission control devices and in a flue, conduit, duct, stack or chimney arranged to conduct emissions to the ambient air.
- The ports shall be located to allow for reliable sampling and shall be adequate for test methods applicable to the facility. Safe sampling platforms and safe access to the platforms shall be provided. Plans and specifications showing the size and location of the ports, platform, and utilities shall be submitted to the Department for review and approval.
4. **Other Testing:**
- a. The Department may require the permittee to have tests conducted to determine the emission of air contaminants from any source, whenever the Department has reason to believe that an emission of a contaminant not addressed by the permit applicant is occurring, or the emission of a contaminant in excess of that allowed by this permit is occurring. The Department may specify testing methods to be used in accordance with good professional practice. The Department may observe the testing. All tests shall be conducted by reputable, qualified personnel. The

Department shall be given a copy of the test results in writing and signed by the person responsible for the tests.

All tests shall be made and the results calculated in accordance with test procedures approved by the Department. All tests shall be made under the direction of persons qualified by training or experience in the field of air pollution control as approved by the Department.

- b. The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide the necessary holes in stacks of ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

- C. **Stack Heights:** Emissions shall be vented through stacks that meet the following height requirements. Stack heights may be no less than those listed in the table below without prior approval from the Department.

Emission Unit Description	Emission Point (EP)	Stack Height (Feet)
ADU Feed Heater #1	1A	128
ADU Feed Heater #2	1B	128
VDU Feed Heater	2A	125
NHT Feed Heater	3A	91
NHT Stabilizer Reboiler	3B	91
NHT Splitter Reboiler	3C	105
CRU Reactor #1/2/3 Heater	4	130
CRU Stabilizer Reboiler	4D	42
CRU Regenerator Vent	4E	40
DHT Feed Heater	5A	96
DHT Splitter Reboiler	5B	91
HYK Reactor Heater	6A	100
HYK Fractionator Heater	6B	100
Thermal Oxidizer	7A	60
Medium Pressure Steam Boiler #1/2/3/4	8	100
High Pressure Steam Boiler #1	8E	100
High Pressure Steam Boiler #2	8F	100
High Pressure Steam Boiler #3	8G	100
Enclosed hydrocarbon (HC) operating flare	10	50
Acid gas flare	10A	150
HC secondary flare #1	10B	150
HC secondary flare #2	10C	150

- D. **Annual Emissions Restrictions:**

- 1. **VOC Emissions Calculations:** By the 15th day of each month, the owner/operator shall calculate and record the total VOC emissions from the following emission units: EUs 1, 1A, 1B, 1C, 2, 2A, 2B, 3, 3A, 3B, 3C, 3D, 4, 4A, 4B, 4C, 4D, 4F, 5, 5A, 5B, 5C, 6, 6A,

6B, 6C, 7, 7A, 7B, 8, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 9, 9A, 9B, 10, 10A, 10B, 10C, 11, 11A, 12, 13, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

$$\text{VOC}_{\text{Total}} = \text{VOC}_{\text{HEATERS/BOILERS}} (\text{EUs } 1\text{A, } 1\text{B, } 2\text{A, } 3\text{A, } 3\text{B, } 3\text{C, } 4\text{A, } 4\text{B, } 4\text{C, } 4\text{D, } 5\text{A, } 5\text{B, } 6\text{A, } 6\text{B, } 7\text{A, } 8\text{A, } 8\text{B, } 8\text{C, } 8\text{D, } 8\text{E, } 8\text{F, } 8\text{G}) + \text{VOC}_{\text{ENGINES}} (\text{EUs } 14\text{A-C, } 15\text{A-C}) + \text{VOC}_{\text{LEAKS}} (\text{EUs } 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 11\text{A}) + \text{VOC}_{\text{TANKS}} \text{ EU } (9\text{A}) + \text{VOC}_{\text{FLARES}} (\text{EUs } 10, 10\text{A, } 10\text{B, } 10\text{C}) + \text{VOC}_{\text{WWTP}} (\text{EU } 12) + \text{VOC}_{\text{CT}} (\text{EU } 13)$$

Where:

$$\text{VOC}_{\text{HEATERS/BOILERS}} = \text{Total VOC emissions (in tons) from EUs } 1\text{A, } 1\text{B, } 2\text{A, } 3\text{A, } 3\text{B, } 3\text{C, } 4\text{A, } 4\text{B, } 4\text{C, } 4\text{D, } 5\text{A, } 5\text{B, } 6\text{A, } 6\text{B, } 7\text{A, } 8\text{A, } 8\text{B, } 8\text{C, } 8\text{D, } 8\text{E, } 8\text{F, } 8\text{G}$$

$$\text{VOC}_{\text{HEATERS/BOILERS}} = (\text{Total heat content of refinery gas combusted in } 1\text{A, } 1\text{B, } 2\text{A, } 3\text{A, } 3\text{B, } 3\text{C, } 4\text{A, } 4\text{B, } 4\text{C, } 4\text{D, } 5\text{A, } 5\text{B, } 6\text{A, } 6\text{B, } 7\text{A, } 8\text{A, } 8\text{B, } 8\text{C, } 8\text{D, } 8\text{E, } 8\text{F, } 8\text{G, million Btu}) \times (0.0054 \text{ lb VOC / million Btu heat input}) / 2000$$

$$\text{VOC}_{\text{ENGINES}} = \text{Total VOC emissions (in tons) from EUs } 14\text{A-C, } 15\text{A-C from non-emergency operations}$$

$$\text{VOC}_{\text{ENGINES}} = [((\text{hours of operation of EUs } 14\text{A-C}) \times (7.05 \times 10^{-4} \text{ lb of VOC / hour of operation}) \times (\text{bhp of EUs } 14\text{A-C})) + ((\text{hours of operation of EUs } 15\text{A-C}) \times (7.05 \times 10^{-4} \text{ lb of VOC / hour of operation}) \times (\text{bhp of EUs } 15\text{A-C}))] / 2000$$

$$\text{VOC}_{\text{LEAKS}} = \text{Total VOC emissions (in tons) from EUs } 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 11\text{A}$$

$$\text{VOC}_{\text{LEAKS}} = \text{Total VOC emissions calculated via ELDAR program monitoring}$$

$$\text{VOC}_{\text{TANKS}} = \text{Total VOC emissions (in tons) from EU } 9\text{A}$$

$$\text{VOC}_{\text{TANKS}} = \text{Calculated utilizing EPA's methodology from Chapter 7 of AP-42: Liquid Storage Tanks}$$

$$\text{VOC}_{\text{FLARING}} = \text{Total VOC emissions (in tons) from EUs } 10, 10\text{A, } 10\text{B, } 10\text{C}$$

$$\text{VOC}_{\text{FLARING-PILOT}} = (\text{total heat content of pilot gas combusted in EU 10, 10A, 10B, and 10C, million Btu}) \times (0.0054 \text{ lb VOC/ million Btu heat input}) / 2000$$

$$\text{VOC}_{\text{FLARING-BLOWDOWN}} = (\text{Blowdown hours}) \times (0.8 \text{ lb VOC / Mbbbl Refining Capacity}) \times (\text{Crude Processing Rate, Mbbbl/day}) / 24 / 2000$$

$$\text{VOC}_{\text{WWTP}} = \text{Total VOC emissions (in tons) from EU 12}$$

$$\text{VOC}_{\text{WWTP}} = (\text{total WWTP flow, 1000 gallons}) \times (0.5 \text{ lb VOC / 1000 gallons of wastewater})$$

$$\text{VOC}_{\text{CT}} = \text{Total VOC emissions (in tons) from EU 13}$$

$$\text{VOC}_{\text{CT}} = [(\text{hours of operation per CT cell}) \times (0.006 \text{ lb/hr})] / 2000$$

Combined VOC emissions from the emission units listed are restricted to 58.0 tons per year. If total calculated combined VOC emissions from emission units 1, 1A, 1B, 1C, 2, 2A, 2B, 3, 3A, 3B, 3C, 3D, 4, 4A, 4B, 4C, 4D, 4F, 5, 5A, 5B, 5C, 6, 6A, 6B, 6C, 7, 7A, 7B, 8, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 9, 9A, 9B, 10, 10A, 10B, 10C, 11, 11A, 12, 13, 14A-C, 15A-C exceed 58.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

2. **CO Emissions Calculations:** By the 15th day of each month, the owner/operator shall calculate and record the total CO emissions from the following emission units: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

$$\text{CO}_{\text{Total}} = \text{CO}_{\text{HEATERS/BOILERS}} (\text{EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G}) + \text{CO}_{\text{FLARES}} (\text{EUs 10, 10A, 10B, 10C}) + \text{CO}_{\text{ENGINES}} (\text{EUs 14A-C, 15A-C})$$

Where:

$$\text{CO}_{\text{HEATERS/BOILERS}} = \text{Total CO emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G}$$

$$\text{CO}_{\text{HEATERS/BOILERS}} = \text{Total CO emissions calculated via use of the CO CEMS for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B}$$

$CO_{\text{HEATERS/BOILERS}}$	=	(Total heat content of refinery gas combusted in EUs 3A, 3B, 3C, 4D, 5A, 5B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G, million Btu) x (CO burners specification ⁵ of lb / million Btu heat input) / 2000
CO_{FLARING}	=	Total CO emissions (in tons) from EUs 10, 10A, 10B, 10C
$CO_{\text{FLARING-PILOT}}$	=	(total heat content of pilot gas combusted in EU 10, 10A, 10B, and 10C, million Btu) x (0.028 lb CO / million Btu heat input) / 2000
$CO_{\text{FLARING-BLOWDOWN}}$	=	(Blowdown hours) x (4.3 lb CO / Mbbbl Refining Capacity) x (Crude Processing Rate, Mbbbl/day) / 24 / 2000
CO_{ENGINES}	=	Total CO emissions (in tons) from EUs 14A-C and 15A-C from non-emergency operations
CO_{ENGINES}	=	$[(\text{hours of operation of EUs 14A-C}) \times (5.5 \times 10^{-3} \text{ lb of CO / hour of operation}) \times (\text{bhp of EUs 14A-C})] + [(\text{hours of operation of EUs 15A-C}) \times (5.5 \times 10^{-3} \text{ lb of CO / hour of operation}) \times (\text{bhp of EUs 15A-C})] / 2000$

Combined CO emissions from the emission units listed are restricted to 80.0 tons per year. If total calculated combined CO emissions from emission units 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C exceed 80.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

3. **NO_x Emissions Calculations:** By the 15th day of each month, the owner/operator shall calculate and record the total NO_x emissions from the following emission units: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

$$NO_{X\text{-Total}} = NO_{X\text{-HEATERS/BOILERS}} (\text{EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G}) + NO_{X\text{-FLARES}} (\text{EUs 10, 10A, 10B, 10C}) + NO_{X\text{-ENGINES}} (\text{EUs 14A-C, 15A-C})$$

Where:

⁵ When calculating emissions, the burner specification shall be utilized unless a Department-approved performance test has been conducted to determine CO emissions from the emission unit. After completion of a Department-approved performance test and verification of the results by the Department, the results of the Department-approved performance test shall be used to calculate emissions.

NO _X -HEATERS/BOILERS	=	Total NO _X emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G
NO _X -HEATERS/BOILERS	=	Total NO _X emissions calculated via use of the NO _X CEMS for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B
NO _X -HEATERS/BOILERS	=	(Total heat content of refinery gas combusted in EUs 3A, 3B, 3C, 4D, 5A, 5B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G, million Btu) x (NO _X burners specification ⁶ of lb / million Btu heat input) / 2000
NO _X -FLARING	=	Total NO _X emissions (in tons) from EUs 10, 10A, 10B, 10C
NO _X -FLARING PILOT	=	(total heat content of pilot gas combusted in EU 10, 10A, 10B, and 10C, million Btu) x (0.03 lb NO _X / million Btu heat input) / 2000
NO _X -FLARING-BLOWDOWN	=	(Blowdown hours) x (19 lb NO _X / Mbbbl Refining Capacity) x (Crude Processing Rate, Mbbbl/day) / 24 / 2000
NO _X -ENGINES	=	Total NO _X emissions (in tons) from EUs 14A-C and 15A-C from non-emergency operations
NO _X -ENGINES	=	[((hours of operation of EUs 14A-C) x (0.013 lb of NO _X / hour of operation) x (bhp of EU14s A-C)) + ((hours of operation of EUs 15A-C) x (0.013 lb of NO _X / hour of operation x (bhp of EU15s A-C)))] / 2000

Combined NO_X emissions from the emission units listed are restricted to 40.0 tons per year. If total calculated combined NO_X emissions from emission units 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C, 14A-C, 15A-C exceed 40.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

4. **SO₂ Emissions Calculations:** By the 15th day of each month, the owner/operator shall calculate and record the total SO₂ emissions from the following emission units: 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10,

⁶ When calculating emissions, the burner specification shall be utilized unless a Department-approved performance test has been conducted to determine NO_X emissions from the emission unit. After completion of a Department-approved performance test and verification of the results by the Department, the results of the Department-approved performance test shall be used to calculate emissions.

10A, 10B, 10C, 14A-C, 15A-C for the previous month and for the previous 12 months (12-month rolling total). Emissions shall be calculated in a method as shown below.

$$\text{SO}_2\text{-Total} = \text{SO}_2\text{-HEATERS/BOILERS (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, 8G)} + \text{SO}_2\text{-FLARES (EUs 10, 10A, 10B, 10C)} + \text{SO}_2\text{-ENGINES (EUs 14A-C, 15A-C)} + \text{SO}_2\text{-SRU (EU 7A)}$$

Where:

$$\text{SO}_2\text{-HEATERS/BOILERS} = \text{Total SO}_2 \text{ emissions (in tons) from EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G}$$

$$\text{SO}_2\text{-HEATERS/BOILERS} = (\text{Total hourly refinery gas combusted in EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G, scf}) \times (\text{hourly fuel gas H}_2\text{S concentration, ppmv}) \times (1 \times 10^{-6}) \times (1 \text{ lb mol}/379 \text{ scf}) \times (64.06 \text{ lb SO}_2 / \text{lb mol SO}_2) / 2000$$

$$\text{SO}_2\text{-SRU} = \text{Total SO}_2 \text{ emissions (in tons) from EU 7A}$$

$$\text{SO}_2\text{-SRU} = \text{Total SO}_2 \text{ emissions calculated via use of SO}_2 \text{ CEMS on EU 7A}$$

$$\text{SO}_2\text{-FLARING} = \text{Total SO}_2 \text{ emissions (in tons) from EUs 10, 10A, 10B, 10C}$$

$$\text{SO}_2\text{-FLARING} = \text{Total SO}_2 \text{ emissions calculated via use of sulfur monitoring}^7$$

$$\text{SO}_2\text{-ENGINES} = \text{Total SO}_2 \text{ emissions (in tons) from EUs 14A-C and 15A-C from non-emergency operations}$$

$$\text{SO}_2\text{-ENGINES} = [((\text{hours of operation of EUs 14A-C}) \times (4.5 \times 10^{-6} \text{ lb of SO}_2 / \text{hour of operation}) \times (\text{bhp of EUs 14A-C})) + ((\text{hours of operation of EUs 15A-C}) \times (4.5 \times 10^{-6} \text{ lb of SO}_2 / \text{hour of operation}) \times (\text{bhp of EUs 15A-C}))] / 2000$$

Combined SO₂ emissions from the emission units listed are restricted to 13.0 tons per year. If total calculated combined SO₂ emissions from emission units 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, 8G, 10, 10A, 10B, 10C,

⁷ Derived via use of sulfur monitoring required by NSPS Subpart Ja.

14A-C, 15A-C exceed 13.0 tons per year in any 12-month period, the permittee shall notify the Department in writing within 15 days of the date the calculation was made.

E. **Monitoring Conditions:**

1. Summary Table:

Emission Unit	EU	EP	Pollutant/ Parameter	Monitoring Requirement	Reference Condition I.I.E.
ADU process equipment	1	Fugitive	VOC	ELDAR	12
			VRU Flow	Recordkeeping	16
ADU Feed Heater #1 rated heat input of 82.13 MMBtu/hr	1A	1A	NO _x	CEMS	6
			CO	CEMS	7
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
ADU Feed Heater #2 rated heat input of 82.13 MMBtu/hr	1B	1B	NO _x	CEMS	6
			CO	CEMS	7
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
ADU sewers	1C	Fugitive	VOC	Inspections/Repairs	11
VDU process equipment	2	Fugitive	VOC	ELDAR	12
			VRU Flow	Recordkeeping	16
VDU Feed Heater rated at 75.00 MMBtu/hr	2A	2A	NO _x	CEMS	6
			CO	CEMS	7
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
VDU sewers	2B	Fugitive	VOC	Inspections/Repairs	11
NHT process equipment	3	Fugitive	VOC	ELDAR	12
			VRU Flow	Recordkeeping	16

Emission Unit	EU	EP	Pollutant/ Parameter	Monitoring Requirement	Reference Condition I.E.
NHT Feed Heater rated 8.60 MMbtu/hr	3A	3A	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
NHT Stabilizer Reboiler rated 9.30 MMbtu/hr	3B	3B	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
NHT Splitter Reboiler rated at 17.90 MMbtu/hr	3C	3C	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
NHT sewers	3D	Fugitive	VOC	Inspections/Repairs	11
CRU process equipment	4	Fugitive	VOC	ELDAR	12
			VRU Flow	Recordkeeping	16
CRU Reactor #1 Heater rated at 45.63 MMbtu/hr	4A	4	NO _x	CEMS	6
			CO	CEMS	7
CRU Reactor #2 Heater rated at 45.63 MMbtu/hr	4B	4	H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
CRU Reactor #3 Heater rated at 45.63 MMbtu/hr	4C	4	Opacity	Recordkeeping	9

Emission Unit	EU	EP	Pollutant/ Parameter	Monitoring Requirement	Reference Condition I.I.E.
CRU Stabilizer Reboiler rated at 5.70 MMbtu/hr	4D	4D	NO _x	Emissions Test/O&M	8
			CO	Emissions Test/O&M	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
CRU Regenerator Vent	4E	4E	Opacity	Recordkeeping	10
CRU sewers	4F	Fugitive	VOC	Inspections/Repairs	11
DHT process equipment	5	Fugitive	VOC	ELDAR	12
DHT Feed Heater rated at 19.50 MMbtu/hr	5A	5A	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
DHT Splitter Reboiler rated at 27.30 MMbtu/hr	5B	5B	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
DHT sewers	5C	Fugitive	VOC	Inspections/Repairs	11
HYK process equipment	6	Fugitive	VOC	ELDAR	12
			VRU Flow	Recordkeeping	16
HYK Reactor Heater rated at 37.16 MMbtu/hr	6A	6A	NO _x	CEMS	6
			CO	CEMS	7
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9

Emission Unit	EU	EP	Pollutant/ Parameter	Monitoring Requirement	Reference Condition I.E.
HYK Fractionator Heater rated at 40.34 MMBtu/hr	6B	6B	NO _x	CEMS	6
			CO	CEMS	7
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
HYK sewers	6C	Fugitive	VOC	Inspections/Repairs	11
SRU process equipment	7	Fugitive	VOC	ELDAR	12
Thermal Oxidizer with a rated capacity of 1.58 MMBtu/hr	7A	7A	SO ₂	CEMS	5
SRU sewers	7B	Fugitive	VOC	Inspections/Repairs	11
Process equipment	8	Fugitive	VOC	ELDAR	12
Medium Pressure Steam Boiler #1 rated at 11.68 MMBtu/hr	8A	8	NO _x	Emissions Test	8
			CO	Emissions Test	8
Medium Pressure Steam Boiler #2 rated at 11.68 MMBtu/hr	8B		SO ₂	Fuel Records	2
Medium Pressure Steam Boiler #3 rated at 11.68 MMBtu/hr	8C		PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
Medium Pressure Steam Boiler #4 rated at 11.68 MMBtu/hr	8D		Opacity	Recordkeeping	9
High Pressure Steam Boiler #1 rated at 22.00 MMBtu/hr	8E	8E	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9

Emission Unit	EU	EP	Pollutant/ Parameter	Monitoring Requirement	Reference Condition I.I.E.
High Pressure Steam Boiler #2 rated at 22.00 MMbtu/hr	8F	8F	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
High Pressure Steam Boiler #3 rated at 22.00 MMbtu/hr	8G	8G	NO _x	Emissions Test	8
			CO	Emissions Test	8
			H ₂ S	CMS (H ₂ S in Fuel Gas)	2
			PM ₁₀ & PM _{2.5} (Filterable + Condensable)	Emissions Test/ Recordkeeping	9
			Opacity	Recordkeeping	9
Process equipment	9	Fugitive	VOC	ELDAR	12
Storage Tank Farm	9A	Various	VOC	Inspections/Repairs	13
Oil Movement sewers	9B	Fugitive	VOC	Inspections/Repairs	11
Enclosed hydrocarbon (HC) operating flare rated to handle up to 24.4 MMscf/day (including purge and fuel gas blowdown)	10	10	Flowrate	Flow monitor / recordkeeping	4
Acid gas flare rated to handle up to 15.8 MMscf/day	10A	10A	Flowrate	Flow monitor / recordkeeping	3
			H ₂ S	CEMs	
			Total Reduced Sulfur (TRS)	Calculation based on CEMs monitoring	
HC secondary flare #1 rated to handle up to 74.6 MMscf/day of emergency relief	10B	10B	Flowrate	Flow monitor / recordkeeping	4
Pressure and Liquid Level	Continuous parameter monitoring system (CPMS)				

Emission Unit	EU	EP	Pollutant/ Parameter	Monitoring Requirement	Reference Condition I.E.
HC secondary flare #2 rated to handle up to 88.8 MMscf/day of emergency relief	10C	10C	Flowrate	Flow monitor / recordkeeping	4
			Pressure and Liquid Level	CPMS	
Process Equipment	11	Fugitive	VOC	ELDAR	12
Truck loading rack vent	11A	11A	VOC	VRU / ELDAR and monthly Olfactory, Visual and Audible (OVA) observations and product throughput	12 / Condition II.A.13
Oil/Separator inlet from Benzene Waste Operators NESHAP (BWON) compliant plant	12	Fugitive	VOC	ELDAR	12
			TAB	Recordkeeping	
CT cell #1	13	13A	Chromium Compounds	Recordkeeping	Condition II.A.15.b
CT cell #2		13B			
CT cell #3		13C			
CT cell #4		13D			
CT cell #5		13E			
Diesel Engine Power Generators rated at 4,700 BHP each	14A	14A	Hours of operation	Maintenance records / hours of operations records	15
	14B	14B			
	14C	14C			
Back-up Diesel Engine Firewater Pumps rated at 350 BHP each	15A	15A	Hours of operation	Maintenance records / hours of operations records	15
	15B	15B			
	15C	15C			

2. **Continuous Monitoring System (CMS) – FGCD Hydrogen Sulfide (H₂S) Monitoring for SO₂ Emissions:** For each FGCD subject to an SO₂ or H₂S limit (EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 8E, 8F, and 8G), the permittee shall comply with the following conditions.
- a. The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of hydrogen sulfide in the fuel gases before being burned in any fuel gas combustion device. Monitoring of H₂S must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(a)(2).
 - b. FGCDs having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned in the respective FGCD. The permittee has elected to monitor

the H₂S concentration on the RFG system header exiting the SRU that is common to all the FGC units to comply with §60.107a(a)(2)(iv).

3. **CEMS and Continuous Parameter Monitoring System (CPMS) – Acid Gas Flare System (EU 10A) Sulfur, H₂S and Total Reduced Sulfur (TRS) Emissions:**
 - a. The presence of a flame shall be monitored using a thermocouple or any other equivalent device approved by the Department.
 - b. The permittee shall install, operate, calibrate a continuous parameter monitoring system to measure and record the flow rate of gas discharged to the flare. Flare gas flow monitoring must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(f).
 - c. The permittee shall comply with the sulfur monitoring requirements in §60.107a(e) for assessing the root cause analysis threshold for the flare.
4. **Continuous Parameter Monitoring – Enclosed HC Flare System (EU 10) and Secondary HC Flares (EU 10B, EU 10C):** For each flare subject to the NSPS Ja standards, the permittee shall comply with the following conditions:
 - a. The presence of a flame shall be monitored using a thermocouple or any other equivalent device approved by the Department.
 - b. The permittee shall operate the pilots using exclusively pipeline quality natural gas.
 - c. The permittee shall install, operate, calibrate a continuous parameter monitoring system to measure and record the flow rate of gas discharged to the flare. Flare gas flow monitoring shall meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(g).
5. **Continuous Emission Monitoring System (CEMS) – SRU Thermal Oxidizer (EP 7A) SO₂ Emissions:** The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of SO₂ and O₂ emissions into the atmosphere. Monitoring of SO₂ and O₂ emissions must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.106a(a)(1).
6. **CEMS – FGCD Nitrogen Oxide (NO_x) Emissions for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B:** The permittee shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor must include an O₂ monitor for correcting the data for excess air. Monitoring of NO_x emissions must also meet all applicable requirements of NSPS Ja, including the applicable requirements of §60.107a(c).

7. **CEMS – FGCD Carbon Monoxide (CO) Emissions for EUs 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B:** The permittee is not required by either State or Federal regulations to install continuous monitor emissions of CO into the atmosphere. However, the permittee has elected to utilize CO CEMS to demonstrate compliance with the facility wide CO emissions restriction under Condition II.D.2. These monitors shall be installed on EU’s 1A, 1B, 2A, 4A, 4B, 4C, 6A, and 6B.
8. **Testing for EUs 3A, 3B, 3C, 4D, 5A, 5B, 8A, 8B, 8C, 8D, 8E, 8F, and 8G:** For compliance demonstration after the initial test, the permittee shall conduct annual portable analyzer testing to provide a reasonable assurance of compliance. The permittee shall conduct an emissions test to measure NO_x and CO emissions, using at a minimum, a portable analyzer with quality assurance procedures equivalent to Conditional Test Methods 22 and/or 30 as outlined in EPA’s Emission Measurement Center⁸. A test shall consist of three runs, with each run at least 20 minutes in length.
9. **Fuel Gas - Opacity and Particulate Matter for EUs 1A, 1B, 2A, 3A, 3B, 3C, 4A, 4B, 4C, 4D, 5A, 5B, 6A, 6B, 7A, 8A, 8B, 8C, 8D, 8E, 8F, and 8G:** For purposes of compliance monitoring after the initial emissions test, burning of gaseous fuel shall be considered credible evidence of compliance with any applicable opacity and particulate matter emission limit. However, results from tests conducted in accordance with the test methods in 40 CFR 60 will take precedence over burning of gaseous fuel for evidence of compliance or noncompliance with any applicable opacity or particulate limit in the event of enforcement action. The permittee shall record the type of fuel used in the source unit on a daily basis.
10. **CRU Regenerator Vent (EU 4E) - Opacity:** For purposes of compliance monitoring, the inherent design and operation of the process vents shall be considered credible evidence of compliance with the visible emissions standards. However, results from tests conducted in accordance with Method 22 of 40 CFR 60, Appendix A will take precedence for evidence of compliance or noncompliance with an applicable visible emission limit, in the event of enforcement action.
11. **40 CFR 60 Subpart QQQ Monitoring/Inspections for EUs 1C, 2B, 3D, 4F, 5C, 6C, 7B, 9B, and 12:** The permittee shall comply with the performance test methods and procedures and compliance provisions of §60.696(a) – (d), as applicable. Additionally, the following affected facilities are subject to the following requirements:
 - a. Individual Drain Systems:
 - i. Drains shall comply with the monitoring requirements of §60.692-2(a)(2)-(5).

⁸ CTM-022 and/or CTM-030. <https://www.epa.gov/emc/emc-conditional-test-methods>

- ii. Junction boxes shall comply with the monitoring requirements of §60.692-2(b)(3)-(4).
 - iii. Sewer Lines shall comply with the monitoring requirements of §60.692-2(c)(2)-(3).
- b. Oily Water Separator: Each OWS shall comply with the monitoring requirements of §60.926-3(a)(3)-(5).
- c. Closed Vent System: Each closed vent system shall comply with the monitoring requirements of §60.692-5(e)(1)-(5).
12. **Enhanced LDAR Monitoring/Inspections/Repairs for EUs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 11A:** The permittee shall comply with the provisions of §63.162 - §63.174 and §63.180.
- a. Each pump in light liquid service shall be monitored following the requirements of §63.163(e).
 - b. Each compressor shall be monitored following the requirements of §63.164(e)-(h).
 - c. All pressure relief devices in gas/vapor service shall be monitored following the requirements of §63.165(a) – (d).
 - d. All sampling connection systems shall be monitored following the requirements of §63.166(a) – (c).
 - e. All open-ended valves and lines shall be monitored following the requirements of §63.167(a) – (e).
 - f. All valves in gas/vapor and light liquid service shall meet the requirements of §63.168(b) – (h).
 - g. Pumps, valves, connectors, and agitators in heavy liquid service; instrument systems; and pressure relief devices in liquid service. All Pumps, valves, connectors, and agitators shall be monitored following the requirements of §63.169(a) – (d).
 - h. Each surge control vessel and bottoms receiver shall be monitored following the requirements of §63.172(a) – (n).
 - i. Each closed-vent systems and control devices shall be monitored following the requirements of §63.172(a) – (n).

- j. Each agitator in gas/vapor and light liquid service shall be monitored following the requirements of §63.173(a) – (j).
 - k. Each connector in gas/vapor service and light liquid service shall be monitored following the requirements of §63.174(a) – (h).
13. **VOL Storage Tanks Inspections/Monitoring/Repairs:**
- a. For the IFR Tanks (301, 302, 305, 306, 307, 308, 309, 311, 312, 327, 328, 331, and 332), the permittee shall comply with the floating roof inspection, monitoring, and repair requirements of §63.1063(c) – (e).
 - b. For the FR Tanks (313, 315, 316, 324, and 325) the permittee shall comply with the fixed roof inspection, monitoring, and repair requirements of §63.1063(c) – (e).
14. **40 CFR 60, Subpart Dc for EUs 8A, 8B, 8C, 8D, 8E, 8F, and 8G:** The permittee shall comply with all applicable requirements of 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.
15. **40 CFR 60, Subpart III for EUs 14A, 14B, 14C, 15A, 15B and 15C:** The permittee shall comply with all applicable requirements of 40 CFR 60, Subpart III – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
16. **40 CFR 60, Subpart NNN for EU 1, 2, 3, 4, 6 and the Benzene Saturation Unit:** The permittee shall operate a properly designed and sized vapor recovery system to collect the vent streams of the affected facilities and comply with the monitoring of emissions and operations provisions of §60.663(b). The permittee shall install, operate, calibrate and maintain a flow indicator to record an instrument for continuously monitoring the vent stream flow from the vapor recovery system to the flare in accordance with §60.662(b).
17. **40 CFR 61, Subpart FF for Waste Water Treatment Plant (EU 12):** The oily water treatment system and individual drain lines that convey process waste water to the oily water treatment system are subject to the applicable requirements of this subpart. Waste that is contained in a segregated stormwater sewer system and any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, are exempt from compliance with the provisions of this subpart.
- a. The permittee shall determine the total annual benzene (TAB) quantity from facility waste by the procedures described in §61.355.
 - b. If the TAB is greater than 1 Mg/year but less than 10 Mg/year, the permittee will comply with the reporting (§61.357) and recordkeeping requirements (§61.356).

- c. Repeat the determination of the TAB at least once a year or when the process changes can cause the TAB to increase above 10 Mg/yr.
- d. Follow the standards set for tanks, containers, drain systems, oil water separators, and closed vent systems and control devices as required under Subpart FF.

18. **Benzene Fenceline Monitoring:** For purposes of operational and additional compliance monitoring, the permittee shall implement a Department approved benzene fenceline monitoring program. The permittee shall maintain records of the program results for a period of 5 years. All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours upon Department request.

F. **Recordkeeping and Reporting Requirements:** All records and reports shall be available for inspection by Department personnel and shall be submitted to the Department upon request. The following records shall be maintained:

1. All recordkeeping and reporting required by applicable federal standards established under 40 CFR 60 - Standards of Performance for New Stationary Sources. The records shall comply with the applicable requirements of the following subparts:

- a. NSPS A: §60.19.
- b. NSPS Dc: §60.48c.
- c. NSPS Ja: §60.108a.

In addition, for EU 10 Flares, make available 15 days after the end of the month: monthly flow, temperature, and hours of operation.

- d. NSPS Kb: §60.115b.

For fixed roof tanks, the permittee shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

- e. NSPS GGGa (references NSPS VVa): §60.486a and §60.487a.
- f. NSPS NNN: §60.665.
- g. NSPS QQQ: §60.697 and §60.698.
- h. NSPS IIII: §60.4214.

Annual reporting [§60.4214(d)] of the EU 14A-C Diesel Generator and EU 15A-C Back-up Diesel Engine Fire Pump engine hours not to exceed 100 hours to include reason for operating (§60.4211(f)(2)(i)). The 100 hour of operation limit includes the sum of hour of operation of the engines in non-emergency use, or maintenance and readiness testing. The number of hours operating in an actual emergency do not have a limit.

Annual reporting [§60.4207(b)] of diesel used by EU 14A-C Diesel Generator and EU 15A-C Back-up Diesel Engine Fire Pump.

2. All recordkeeping required by applicable federal standards established under 40 CFR Part 61 – National Emission Standards for Hazardous Air Pollutants.

- a. NESHAP FF: §63.356 and §63.357.

Annual calculation of the annual average benzene concentration of waste streams.

3. All recordkeeping required by applicable federal standards established under 40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants for Source Categories.

- a. MACT H: §63.181 and §63.182.

- b. MACT WW: §63.1065 and §63.1066.

- c. MACT 6B: §63.11094 and §63.11095.

Gasoline Loading Rack ELDAR inspection (500 ppmv).

Gasoline Loading Rack OVA and/or LDAR leak inspection on all equipment in gasoline service (§63.11089).

Gasoline Loading Rack monthly gasoline throughput made available 15 days after the end of the month.

4. Additional Requirements

- a. All stack test results including field data, laboratory analysis data, and quality assurance data.

- b. Semi-Annual reporting of CEMS observations for all units subject to monitoring.

- c. Annual Emission Inventory/Annual Production Reports: The owner/operator shall submit an annual emission inventory report and/or an annual production report upon Department request, on forms supplied or approved by the Department.

The owner/operator shall maintain any compliance monitoring records required by this permit or applicable requirements. The owner/operator shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information may include all calibration and maintenance records and all original strip-chart recordings/computer printouts for continuous monitoring instrumentation, and copies of all reports required by the permit.

General Conditions

- G. **Construction:** Construction of the above described facility shall be in accordance with information provided in the permit application as well as any plans, specifications and supporting data submitted to the Department. The Department shall be notified ten days in advance of any significant deviations from the specifications furnished. The issuance of this Permit to Construct may be suspended or revoked if the Department determines that a significant deviation from the plans and specifications furnished has been or is to be made.
- Any violation of a condition issued as part of this permit to construct as well as any construction which proceeds in variance with any information submitted in the application, is regarded as a violation of construction authority and is subject to enforcement action.
- H. **Startup Notice:** A notification of the actual date of initial startup shall be submitted to the Department within 15 days after the date of initial startup.
- I. **Organic Compounds Emissions:** The permittee shall comply with all applicable requirements of NDAC 33-15-07 – Control of Organic Compounds Emissions.
- J. **Air Pollution from Internal Combustion Engines:** The permittee shall comply with all applicable requirements of NDAC 33-15-08-01 – Internal Combustion Engine Emissions Restricted.
- K. **Fugitive Emissions:** The release of fugitive emissions shall comply with the applicable requirements in NDAC 33-15-17.
- L. **Title V Permit to Operate:** Within one year after startup of the units covered by this Permit to Construct, the owner/operator shall submit a permit application for a Title V Permit to Operate for the facility.
- M. **Permit Invalidation:** This permit shall become invalid if construction is not commenced within eighteen months after issuance of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time.
- N. **Source Operations:** Operations at the installation shall be in accordance with statements, representations, procedures and supporting data contained in the initial application, and any

supplemental information or application(s) submitted thereafter. Any operations not listed in this permit are subject to all applicable North Dakota Air Pollution Control Rules.

- O. **Alterations, Modifications or Changes:** Any alteration, repairing, expansion, or change in the method of operation of the source which results in the emission of an additional type or greater amount of air contaminants or which results in an increase in the ambient concentration of any air contaminant, must be reviewed and approved by the Department prior to the start of such alteration, repairing, expansion or change in the method of operation.
- P. **Nuisance or Danger:** This permit shall in no way authorize the maintenance of a nuisance or a danger to public health or safety.
- Q. **Malfunction Notification:** The owner/operator shall notify the Department of any malfunction which can be expected to last longer than twenty-four hours and can cause the emission of air contaminants in violation of applicable rules and regulations.
- R. **Operation of Air Pollution Control Equipment:** The owner/operator shall maintain and operate all air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.
- S. **Transfer of Permit to Construct:** The holder of a permit to construct may not transfer such permit without prior approval from the Department.
- T. **Right of Entry:** Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B of this permit is located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.
- U. **Other Regulations:** The owner/operator of the source unit(s) described in Item I.B of this permit shall comply with all State and Federal environmental laws and rules. In addition, the owner/operator shall comply with all local burning, fire, zoning, and other applicable ordinances, codes, rules and regulations.
- V. **Permit Issuance:** This permit is issued in reliance upon the accuracy and completeness of the information set forth in the application. Notwithstanding the tentative nature of this information, the conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has, or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25.
- W. **Odor Restrictions:** The owner/operator shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33-15-16.

- X. **Sampling and Testing:** The Department may require the owner/operator to conduct tests to determine the emission rate of air contaminants from the source. The Department may observe the testing and may specify testing methods to be used. A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the owner/operator shall follow the procedures and formats in the Department's Emission Testing Guideline.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date _____

By _____

Terry L. O'Clair, P.E.
Director
Division of Air Quality

DRAFT