



Tipane, Frederick <frederick.tipane@wv.gov>

Fwd: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Tipane, Frederick <frederick.tipane@wv.gov>

Fri, Aug 22, 2025 at 7:56 AM

To: Evan Gay <Evan.Gay@ergon.com>, Greir Merchant <Greir.Merchant@ergon.com>, Caleb Gingerich <caleb.gingerich@trinityconsultants.com>, George Mesing <GMesing@trinityconsultants.com>, Dan Shaw <Dan.Shaw@ergon.com>

Good morning Evan,

I only sent the updated Pre-Draft/Proposed permit to you in the previous email. I have attached the response to comments to this one.

Let me know if you have any questions. I will be out of the office the rest of the day and will be back on Monday.

Thanks,
Fred

----- Forwarded message -----

From: **Tipane, Frederick** <frederick.tipane@wv.gov>

Date: Thu, Aug 21, 2025 at 5:09 PM

Subject: Re: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

To: Evan Gay <Evan.Gay@ergon.com>

Cc: Greir Merchant <Greir.Merchant@ergon.com>, Caleb Gingerich <caleb.gingerich@trinityconsultants.com>, George Mesing <gmesing@trinityconsultants.com>, Dan Shaw <Dan.Shaw@ergon.com>

Evan,

Attached are my responses to Ergon's Pre-Draft Title V permit comments. Most of the comments dealt with the requirements in the Pre-draft R13-2334AK permit. Ed and I worked together to address the R13 issues so that the Title V requirements will be the same.

Once R13-2334AK is issued, I will finalize the Title V permit and start the public notice period and EPA's comment period before the end of next week.

Should have any questions let me know.

Thanks,
Fred

On Mon, Aug 18, 2025 at 10:15 AM Evan Gay <Evan.Gay@ergon.com> wrote:

Good morning, Fred –

Please find our comments attached. Let me know if you have any questions at all.

As always, we appreciate your work on this.

Evan

Evan Gay

Sr Environmental Engineer

Corporate Environmental – Projects Team

Ergon, Inc.

M 601-337-1591
P 601-933-3097



From: Tipane, Frederick <frederick.tipane@wv.gov>

Sent: Wednesday, July 30, 2025 2:35 PM

To: Evan Gay <Evan.Gay@ergon.com>; Greir Merchant <Greir.Merchant@ergon.com>

Subject: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

Good afternoon Evan and Greir,

Please find attached for your review the Pre-Draft Permit R30-02900008-2021(SM01, MM03) and Fact Sheet for Ergon West Virginia's Newell Refinery. I have included the Pre-Draft revisions of R13-2334AK and highlighted them in yellow. I will finalize the requirements once R13-2334AK is issued. Since my deadline for issuance is rapidly approaching, I'm requesting that you submit any comments or questions regarding the permit and/or fact sheet to me as soon as possible but no later than August 18, 2025.

Please feel free to contact me with any questions or concerns or if you wish to discuss any issues..

Regards,

Fred

--



Frederick Tipane

Division of Air Quality

601 57th Street, SE

Charleston, WV 25304
(304) 414-1910

frederick.tipane@wv.gov

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2 attachments



Pre-DPPermit03,04 R30-02900008-2021(SM01, MM03)_R1.docx
9662K



Response to Comments_Pre-DPPermit03 R30-02900008-2021(SM01 MM03) - Trinity Comments v2.0.docx
9692K

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:

Ergon – West Virginia, Inc.

Newell Refinery

R30-02900008-2021

Laura M. Crowder

Director, Division of Air Quality

Issued: February 9, 2021 • Effective: February 23, 2021
Expiration: February 9, 2026 • Renewal Application Due: August 9, 2025

Permit Number: **R30-02900008-2021**
Permittee: **Ergon – West Virginia, Inc.**

Facility Name: **Newell Refinery**

Permittee Mailing Address: **9995 Ohio River Blvd, P. O. Box 356, Newell, WV 26050**

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:	9995 Ohio River Blvd., Newell, Hancock County, West Virginia
Telephone Number:	304-387-4343
Type of Business Entity:	Corporation
Facility Description:	Petroleum Refinery
SIC Codes:	2911
UTM Coordinates:	531.25 km Easting • 4495.35 km Northing • Zone 17

Permit Writer: Robert Mullins

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.

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

1.1 Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
CDU	CDU	Crude Distillation Unit	1972/2012/2015	9,617,750 bbls/yr	00A-01
001-01	H-101R	CDU Atmospheric Heater; refinery fuel gas/natural gas blend	2012	54.5 MMBtu/hr	N/A
001-02	H-102R	CDU Vacuum Heater; refinery fuel gas/natural gas blend	2012	39.2 MMBtu/hr	N/A
002-01	H-201	PDR Heater; refinery fuel gas/natural gas blend	1972	6.6 MMBtu/hr	N/A
003-01	MEK-TOL	Solvent Dewaxing Unit	1972	N/A	N/A
004-01	H-500S	H500 Series Heaters (5 heaters to common stack) Unifiner/Platformer Unit; refinery fuel gas/natural gas blend	1972/2013/2016 ~~2015~~	59.6 MMBtu/hr	N/A
004-02	H-501R	Unifiner Charge Heater	2013	11.5 MMBtu/hr	N/A
005-01	H-600S	H600 Series Heaters, (4 heaters to common stack) ISOMAX Unit; refinery fuel gas/natural gas blend	1972	41.6 MMBtu/hr	N/A
005-02	H-441	Hydrogen Plant Heater; natural gas	1972	12.3 MMBtu/hr	N/A
006-01	H-701	VFU Heater; refinery fuel gas/natural gas blend	1983	12.1 MMBtu/hr	N/A
EPN 01	H-901	DHT Heater	2005	27.5 MMBtu/hr	N/A
EPN 03	H-1101	Hydrogen Plant Heater	2005	38.8 MMBtu/hr	N/A
007-01	Boiler A	Boiler A; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	N/A
007-02	Boiler B	Boiler B; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	N/A
007-03	Boiler C	Boiler C; refinery fuel gas/natural gas blend	2000	95 MMBtu/hr	N/A
TDB01	TDB01	Solar Titan 130-23001S Natural Gas Fired Combustion Turbine (CT) with generator coupled with heat recovery steam generator (HRSG)	2025	15 MW (gross output)	n/a
		Refinery fuel gas/natural gas blend fired duct burner		77.6 MMBtu/hr	n/a
CCT01	CCT01	COGEN Fluid Cooler (closed circuit cooling unit)	2025	2,016 GPM	n/a
Portable Boiler	Portable Boiler	Portable Boiler; Natural Gas	2020	99.9 MMBtu/hr Max	N/A
009-01	T Load	Truck Loading	1972/2012/2013	397.8 MMgal/yr	00A-02*

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
Rail-UL	Rail-UL	Rail Car Unloading	2019	800 gpm	N/A
009-02	MLD	Marine Barge Loading	1972/2012	460.7 MMgal/yr	00A-04**
00A-01	F1	Main Flare	1972	N/A	N/A
00A-03	F2	Sour Gas Flare	1972	N/A	N/A
00A-02	OXIDIZER	Thermal Oxidizer - 98.7% Min Efficiency	1994/2012 /2013	17,346 MMBtu/yr	N/A
00A-04	MLDOX	Barge Loading Thermal Oxidizer - 98% Min Eff	2012	59.0 MMBtu/hr	N/A
00B-01	WWT	Wastewater Treatment Plant	1972/1997	600 gpm	00A-03
00B-02	EQLEAKS	Equipment Leak Fugitives	N/A	N/A	N/A
00D-01	Dehy Htr	Dehydration Heater	1991	0.59 MMBtu/hr	N/A
00D-02	Still	Glycol Dehydration Still	1991	N/A	N/A
~~EPN-01~~	~~H-901~~	~~DHT Heater~~	~~2005~~	~~27.5 MMBtu/hr~~	~~N/A~~
~~EPN-03~~	~~H-1101~~	~~Hydrogen Plant Heater~~	~~2005~~	~~38.8 MMBtu/hr~~	~~N/A~~
FWPUMP1	FWPUMP1	Diesel Firewater Pump at River Dock	2005	210 hp	N/A
FWPUMP2	FWPUMP2	Diesel Firewater Pump at Boiler House	1993	265 hp	N/A
CEG01	CEG01	COGEN Black-Start Diesel Emergency Generator (Generac Model S12R-Y2PTAQ-1; Model Yr. 2023 or later)	2025	1,881 HP	N/A

Tanks

4000	TK-4000	External floating roof; crude oil; mechanical shoe	1992/2012	2,310,000 gallons	N/A
4001	TK-4001	External floating roof; crude oil; mechanical shoe	1973/2012	2,310,000 gallons	N/A
4002	TK-4002	External floating roof; heavy products or kerosene; mechanical shoe	1970	2,310,000 gallons	N/A
4003	TK-4003	External floating roof; heavy products or kerosene; mechanical shoe	1970	2,310,000 gallons	N/A
4004	TK-4004	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4005	TK-4005	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4006	TK-4006	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4007	TK-4007	Fixed roof; heavy products	1971	2,310,000 gallons	N/A
4008	TK-4008	Fixed roof; heavy products	1970	1,260,000 gallons	N/A
4009	TK-4009	Fixed roof; heavy products or kerosene	1971	1,260,000 gallons	N/A
4010	TK-4010	Fixed roof; heavy products	1970	1,260,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
4011	TK-4011	Fixed roof; heavy products or kerosene	1971	1,239,568 gallons	N/A
4012	TK-4012	Internal floating roof; gasoline; vapor mounted	1971	630,000 gallons	N/A
4013	TK-4013	Internal floating roof; gasoline; vapor mounted	1971	630,000 gallons	N/A
4014	TK-4014	External floating roof; gasoline; mechanical shoe	1971/2013	315,000 gallons	N/A
4015	TK-4015	External floating roof; gasoline; mechanical shoe	1971/2013	315,000 gallons	N/A
4016	TK-4016	External floating roof; gasoline; mechanical shoe	1971	315,000 gallons	N/A
4017	TK-4017	Fixed roof; heavy products	1971	840,000 gallons	N/A
4018	TK-4018	Fixed roof; heavy products	1971/2000	704,970 gallons	N/A
4019	TK-4019	Fixed roof; heavy products	1971	704,970 gallons	N/A
4020	TK-4020	Fixed roof; heavy products	1971	840,000 gallons	N/A
4021	TK-4021	Fixed roof; heavy products	1971	840,000 gallons	N/A
4022	TK-4022	Fixed roof; heavy products	1971	571,200 gallons	N/A
4023	TK-4023	Fixed roof; heavy products	1971	571,200 gallons	N/A
4024	TK-4024	Fixed roof; heavy products	1970	840,000 gallons	N/A
4025	TK-4025	Fixed roof; heavy products	1970	840,000 gallons	N/A
4026	TK-4026	Fixed roof; heavy products	1970	840,000 gallons	N/A
4027	TK-4027	Fixed roof; heavy products	1971	840,000 gallons	N/A
4028	TK-4028	Fixed roof; heavy products	1970	210,000 gallons	N/A
4029	TK-4029	Fixed roof; heavy products	1971	65,100 gallons	N/A
4030	TK-4030	Fixed roof; heavy products	1971	65,100 gallons	N/A
4031	TK-4031	Fixed roof; heavy products	1971	315,000 gallons	N/A
4032	TK-4032	Fixed roof; heavy products	1971	315,000 gallons	N/A
4033	TK-4033	Fixed roof; heavy products	1970	315,000 gallons	N/A
4034	TK-4034	Fixed roof; heavy products	1998	840,000 gallons	N/A
4035	TK-4035	Fixed roof; heavy products	1983	840,000 gallons	N/A
4036	TK-4036	Fixed roof; heavy products	1973	315,000 gallons	N/A
4037	TK-4037	Fixed roof; heavy products	1973	315,000 gallons	N/A
4038	TK-4038	Fixed roof; heavy products	1976	840,000 gallons	N/A
4039	TK-4039	Fixed roof; heavy products	1977	1,260,000 gallons	N/A
4040	TK-4040	Fixed roof; heavy products	1978	630,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
4041	TK-4041	Fixed roof; heavy products	1973	630,000 gallons	N/A
4042	TK-4042	Fixed roof; heavy products	1978	630,000 gallons	N/A
4043	TK-4043	Fixed roof; heavy products	1978	630,000 gallons	N/A
4044	TK-4044	Fixed roof; heavy products	1982	1,260,000 gallons	N/A
4045	TK-4045	Fixed roof; heavy products	1982	630,000 gallons	N/A
4046	TK-4046	Fixed roof; heavy products	1982	630,000 gallons	N/A
4047	TK-4047	Fixed roof; heavy products, MTVP <3.5kPa	1986	1,260,000 gallons	N/A
4048	TK-4048	Fixed roof; heavy products	1986	504,000 gallons	N/A
4050	TK-4050	Internal floating roof; gasoline; mechanical shoe	1993/2013	630,000 gallons	N/A
4051	TK-4051	Fixed roof; heavy products, MTVP <3.5kPa	1996	1,260,000 gallons	N/A
4052	TK-4052	Fixed roof; ethanol	1972	30,240 gallons	N/A
4053	TK-4053	Fixed roof; ethanol	1972	30,240 gallons	N/A
4054	TK-4054	Fixed roof; heavy products or kerosene	1998	625,000 gallons	N/A
4055	TK-4055	Fixed roof; heavy products or kerosene	1998	625,000 gallons	N/A
4056	TK-4056	Fixed roof; heavy products or kerosene	1999	625,000 gallons	N/A
4057	TK-4057	Fixed roof; heavy products or kerosene	1999	625,000 gallons	N/A
4060	TK-4060	Internal floating roof; crude; mechanical shoe	1999/2012 /2015	5,040,000 gallons	N/A
4061	TK-4061	Internal floating roof; crude; mechanical shoe	2008/2012 /2015	5,040,000 gallons	N/A
4062	TK-4062	Internal floating roof; light crude oil with vapor pressure < 11.0 psia; mechanical shoe	2008/2012	5,040,000 gallons	N/A
4063	TK-4063	Internal floating roof; light crude oil with vapor pressure < 11.0 psia; mechanical shoe	2012	5,040,000 gallons	N/A
4066	TK-4066	Fixed roof; Biodiesel Tank	2011	40,000 gallons	N/A
4069	TK-4069	Fixed roof; Biodiesel Tank	2017	126,000 gallons	N/A
4070	TK-4070	Internal floating roof; ethanol; mechanical shoe	2018	630,000 gallons	N/A
4071	TK-4071	External floating roof; gasoline; mechanical shoe	2018	1,260,000 gallons	N/A
4072	TK-4072	Fixed roof; feedstock	2018	1,260,000 gallons	N/A
4073	TK-4073	Fixed roof; heavy products	2020	32,800 barrels	N/A
4103	TK-4103	Fixed roof; heavy products	1970	127,000 gallons	N/A
4104	TK-4104	Fixed roof; heavy products	1970	127,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
V-4002	V-4002	NGL Bullet Tank	2016	10,984 ft ³	fuel gas system
V-4003	V-4003	NGL Bullet Tank	2016	10,984 ft ³	fuel gas system
00A-03	CARBONBED	Carbon Bed Adsorber	2002	6,000 cfm	N/A
Process Vessels					
303	TK-303	Fixed roof; MEK	1970	7,875 gallons	N/A
304	TK-304	Fixed roof; Toluene	1970	7,875 gallons	N/A
NS-FUG	NS-FUG	Naphtha Splitter Fugitives	2011	N/A	N/A
ISOM	ISOM	Processing Unit: Benzene Reduction	2012	21.6 MMgals/yr	N/A
ADU	NH3OX	Ammonia Destruction Unit	2015	N/A	00A-05
00A-05	NH3OX	Ammonia Destruction Unit Thermal Oxidizer - 99.9% DRE	2015	6.6 MMBtu/hr	N/A
ADUFUG	ADUFUG	Ammonia Destruction Unit Fugitives	2015	N/A	N/A
PL-FUG	PL-FUG	Platformer Expansion Fugitives	2015	N/A	N/A
YNGL-FUG	YNGL-FUG	Y-Grade NGL Fugitives	2015	N/A	N/A

* Control Device for Gasoline Loading Only

** Control Device for Gasoline and Light Crude Oil Loading Only

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
R13-2334AK AI	August 22, 2025 September 23, 2021

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 ~~such~~ 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~~, ~~2.42~~). 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
CBI	Confidential Business Information		Standards
CEM	Continuous Emission Monitor	PM	Particulate Matter
CES	Certified Emission Statement	PM₁₀	Particulate Matter less than 10µm in diameter
C.F.R. or CFR	Code of Federal Regulations		
CO	Carbon Monoxide	pph	Pounds per Hour
C.S.R. or CSR	Codes of State Rules	ppm	Parts per Million
DAQ	Division of Air Quality	PSD	Prevention of Significant Deterioration
DEP	Department of Environmental Protection	psi	Pounds per Square Inch
FOIA	Freedom of Information Act	SIC	Standard Industrial Classification
HAP	Hazardous Air Pollutant		
HON	Hazardous Organic NESHAP	SIP	State Implementation Plan
HP	Horsepower	SO₂	Sulfur Dioxide
lbs/hr or lb/hr	Pounds per Hour	TAP	Toxic Air Pollutant
LDAR	Leak Detection and Repair	TPY	Tons per Year
m	Thousand	TRS	Total Reduced Sulfur
MACT	Maximum Achievable Control Technology	TSP	Total Suspended Particulate
		USEPA	United States Environmental Protection Agency
mm	Million		
mmBtu/hr	Million British Thermal Units per Hour	UTM	Universal Transverse Mercator
mmft³/hr or mmcf/hr	Million Cubic Feet Burned per Hour	VEE	Visual Emissions Evaluation
NA or N/A	Not Applicable		
NAAQS	National Ambient Air Quality Standards	VOC	Volatile Organic Compounds
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 ~~39~~]

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](#) ~~Emergency~~

~~2.17.1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.~~

~~[45CSR§30-5.7.a.]~~

~~2.17.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology based emission limitations if the conditions of 45CSR§30-5.7.c. are met.~~

~~[45CSR§30-5.7.b.]~~

~~2.17.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:~~

- ~~a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;~~
- ~~b. The permitted facility was at the time being properly operated;~~
- ~~c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and~~

~~d. Subject to the requirements of 45CSR§30-5.1.c.3.C.1, the permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice, report, and variance request fulfills the requirement of 45CSR§30-5.1.c.3.B. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.~~

~~[45CSR§30-5.7.c.]~~

~~2.17.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.~~

~~[45CSR§30-5.7.d.]~~

~~2.17.5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.~~

~~[45CSR§30-5.7.e.]~~

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. and ~~45CSR38~~]

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](#) ~~14~~)]**
- 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.** This stationary source, as defined in 40 CFR § 68.3, is subject to Part 68. This stationary source has submitted a risk management plan (RMP) by the date specified in 40 CFR §68.10. This stationary source shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 CFR Part 70 or 71.

[40 CFR 68]

- 3.1.9. **Sulfur Dioxide.** The Company agrees that it shall not operate any source of sulfur dioxide emissions unless such source is in compliance with the Code, terms of CO-SIP-95-1, and any additional or more stringent provisions of 45CSR10 - "To Prevent and Control Air Pollution From the Emissions of Sulfur Oxides".

[CO-SIP-95-1 - IV.1. (SIPed)]

- 3.1.10. **Sulfur Dioxide.** The Company agrees that at all times, including periods of source start-up, shut down, and malfunction, that it will, to the extent practicable, maintain and operate all sources of sulfur dioxide emissions, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.

[CO-SIP-95-1 - IV.2. (SIPed)]

- 3.1.11. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, operate, and maintain 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.

[45CSR13: Permit R13-2334, [4.1.20](#), ~~4.1.5~~, 45CSR§13-5.10, ~~11~~.]

- 3.1.12. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-2334 through R13-~~2334~~[AK](#) ~~AIF~~ and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to.

[45CSR13: Permit R13-2334, 2.5.1.]

- 3.1.13. Facility wide emissions of all combined HAPs (including combustion related HAPs) shall not exceed 24.99 tons per year. Facility wide emissions of any individual HAP (including combustion related HAPs) shall not exceed 9.99 tons per year. Compliance with this condition shall be determined using a rolling 12 month total.

[45CSR13: Permit R13-2334, 12.1.1]

3.2. Monitoring Requirements

- 3.2.1. In order to determine compliance with this condition, the applicant shall calculate facility wide emissions of HAPs on a monthly basis. Said emission calculations shall be based on one of the following:
 - a. Continuous Emissions Monitoring
 - b. Predictive Emissions Monitoring

- c. USEPA approved source testing
- d. Material balance
- e. AP-42
- f. Manufacturer's Data

[45CSR13: Permit R13-2334, 12.2.1]

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 in 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)(~~14-15-16~~) 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.; R13-2334, 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.]

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 Maintenance of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures. **[45CSR13: Permit R13-2334, Condition 4.4.2.]**

3.4.5. **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: Permit R13-2334, Condition 4.4.3.]

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](#) ~~Section~~ (3ED21)
[Four Penn Center](#)
[1600 John F. Kennedy Boulevard](#) ~~1650 Arch Street~~
Philadelphia, PA 19103-[2852](#) ~~2029~~

DAQ Compliance and Enforcement¹:

DEPAirQualityReports@wv.gov

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

- 3.5.4. ~~**Fees. Certified emissions statement.**~~ The permittee shall ~~submit a certified emissions statement and~~ pay fees on an annual basis in accordance with [45CSR§30-8](#). ~~the submittal requirements of the Division of Air Quality.~~
[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:

DEPAirQualityReports@wv.gov

US EPA:

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. Emergencies.**~~ ~~For reporting emergency situations, refer to Section 2.17 of this permit.~~
- 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. Any deviation resulting from an emergency or upset condition, as defined in 45CSR§30-5.7., shall be reported by telephone or telefax within one (1) working day of the date on which the permittee becomes aware of the deviation, if the permittee desires to assert the affirmative defense in accordance with 45CSR§30-5.7. A written report of such deviation, which shall include the probable cause of such deviations, and any corrective actions or preventative measures taken, shall be submitted and certified by a responsible official within ten (10) days of the deviation.~~
 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](#) ~~telefax~~. 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. EWVI has certified that it has completed its obligations from the Consent Judgment (97-C-338), therefore the requirements from the Consent Judgment are no longer included in the Title V Permit.

- b. 40 CFR Part 60, Subpart D - The boilers at the Newell Refinery do not have rated capacities greater than 250 MMBTU/hr.
- c. 40 CFR Part 60, Subpart Da - The boilers at the Newell Refinery are not in electric utility service and do not have rated capacities greater than 250 MMBTU/hr.
- d. 40 CFR Part 60, Subpart Db - The Newell Refinery does not have steam generating units that commenced construction, modification or reconstruction after June 19, 1984 with a rated capacity greater than 100 MMBTU/hr.
- e. 40 CFR Part 60 Subpart Dc - National Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units does not apply to process heaters H-101R, H-102R, and H-501R because although they have maximum design heat inputs between 10 and 100 MMBtu/hr, they do not meet the definition of a “steam generating unit.” The Portable Boiler is also not subject to this subpart since it is defined as a temporary boiler and per 40 C.F.R. §60.40c(i), “temporary boilers” are not subject to the subpart.
- f. 40 CFR Part 60 Subpart RRR - National Standards of Performance for Volatile Organic Compounds (VOC) Emissions from Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Reactor Processes does not apply to EWVI since it does not produce any of the chemicals listed in 40 CFR §60.707 as a product, co-product, by-product, or intermediate.
- g. 40 CFR Part 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene. The provisions of this subpart apply to each of the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges, and other connectors, product accumulator vessels, and control devices or systems required by this subpart. To be covered by this Subpart, the equipment must be in benzene service. In benzene service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The Newell Refinery does not have any equipment that is in benzene service.
- h. 40 CFR Part 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources). The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air pollutant service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges, and other connectors, product accumulator vessels, and control devices or systems required by this subpart.

The provisions of this subpart apply after the promulgation of a specific subpart in Part 61. For example, If the refinery was subject to 40 CFR Part 61, Subpart J (which it is not), then the refinery would have to comply with the equipment leak provisions of 40 CFR Part 61, Subpart V. The actual equipment leak standards are contained in Subpart V. If one is subject to Subpart J, then Subpart J refers one to Subpart V for the actual compliance standards. In summary, the Newell Refinery would have to be subject to some other subpart in Part 61 that referred to Subpart V before Subpart V would be applicable.

- i. 40 CFR Part 63 - EWVI has demonstrated that the facility is not a major source of HAPs and never has been. MEK is a major constituent of the EWVI HAP emissions and has now been delisted. [70 Fed. Reg. 75047 (December 19, 2005)] Further, EPA has made the determination that the delisting of MEK may be applied retroactively. Therefore, the “once in, always in” policy would not apply. In addition,

more accurate emissions calculation methodologies have been developed for estimating fugitive emissions. Applying the more accurate emissions methodologies demonstrates that emissions from the MEK-TOL unit never exceeded the major threshold, even when combined with other sources of HAP emissions at the refinery. Retroactively applying the more accurate calculation methods for determining fugitive emissions from the MEK-TOL unit, added to the rest of the facility's HAP emissions, determined that facility-wide HAP PTEs have always been less than 10 tons per year of a single HAP and 25 tons per year of aggregate HAPs. Therefore, 40 CFR Part 63, Subparts H, R, Y, CC, OO, PP, QQ, RR, VV, UUU, EEEE, [YYYY](#), GGGGG, and DDDDD do not apply to this source.

- j. 40 CFR Part 63 Subpart JJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers, which is an area source MACT rule, does not apply to EWVI's boilers and process heaters per 40 CFR §63.11195 (e), since they are gas fired.

4.0 Fuel Burning Units Requirements [Boilers A, B, & C, Portable Boiler, [Process](#) Heaters H-101R, H-102R, H-201, H-500S, H-501R, H-600S, H-441, H-701, H-901, and H-1101; [Combustion Turbine w/Duct Burner](#)]

Emission Unit	Applicable Rule	Limits Section 4.1:	Monitoring Section 4.2:	Testing Section 4.3:	Recordkeeping Section 4.4:	Reporting Section 4.5
Boilers A&B	45CSR2	1, 2, 3, 4, 7, 8, 9	3		2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5, 8	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 14, 25	1, 3, 8, 9, 13		1, 2, 3, 4, 5, 6, 8	1, 2
	CO-SIP-95	15, 16	2, 4, 5, 6, 7, 9	2, 3	7, 8	3, 4
	40CFR60	9, 12, 25	9		6	
Boiler-C	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13, 17	8		4, 5	
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 17, 25	1, 8, 9, 10, 11		1, 2, 3, 4, 5, 9	1, 5, 6
	CO-SIP-95		9	3		
	40CFR60	9, 12, 25	9			5
Portable Boiler	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 28, 29, 30, 31, 32	1, 15		2, 3, 19, 20	1
H-101R & H-102R	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 18, 26, 27	1, 8, 14	1	1, 2, 3, 4, 5, 12, 18	1, 2, 8, 9
	40CFR60	9, 18, 26, 27	14	1	16	8, 9
H-201	45CSR2	1, 2, 3, 4				
	45CSR10	5			14	
	45CSR13	1, 3, 4, 6, 12, 19, 25	1, 9		1, 6, 14	
	CO-SIP-95		2, 9, 10	2, 3	7, 14	3, 4
	40CFR60	12, 25	9		6	
H-441	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 19				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 10, 11, 19, 20	1		1, 2, 3, 13	1
	CO-SIP-95	20	2, 7			3, 4
	40CFR60	9				
H-701	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13, 19	8		4, 5, 14	
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 19, 25	1, 8, 9		1, 2, 3, 4, 5, 6, 14	1
	CO-SIP-95	21	2, 7, 9	2, 3	7, 14	3, 4
	40CFR60	9, 12, 25	9		6	
H-500S & H-600S	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5, 14	2
	CO-SIP-95		2, 7, 9, 10	2, 3	7, 14	3, 4
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 22, 25	1, 8		1, 2, 3, 4, 5, 14	1, 2
	500S-only	26	14	1	18	8, 9
	600S-only	12	9		6	
	40CFR60	9, 25				
	500S-only	26	14	1	18	8, 9

Emission Unit	Applicable Rule	Limits Section 4.1.	Monitoring Section 4.2.	Testing Section 4.3.	Recordkeeping Section 4.4.	Reporting Section 4.5
	600S only	12	9		6	
H-501R	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 18, 26, 27	1, 8, 14	1	1, 2, 3, 4, 5, 12, 18	1, 2, 8, 9
	40CFR60	9, 18, 26, 27	14	1	18	8, 9
H-901	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8			2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 23, 25	1, 8, 9, 11		1, 2, 3, 6, 15, 16	1, 2, 7
	CO-SIP-95		9	3	7	
H-1101	40CFR60	9, 12, 25	9		6	7
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 23, 24	1, 12		1, 2, 3, 17	1

4.1. Limitations and Standards

All boilers and heaters

4.1.1. Boilers A and B are “fuel gas combustion device” under Subpart J of 40 CFR 60 and “fuel burning units” under 45CSR2 and 45CSR10; and “combusting refinery gas stream” in Section 5 of 45CSR10. The following conditions and requirements are specific to boilers identified as Boiler A and Boiler B: ~~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.~~

- a. The emissions released from each Emission Points “Boiler A” and “Boiler B” shall not exceed following individual emission rates.

CO & VOC limits for Boilers A and B		
Pollutant	Emission Rate	
	TPM	TPY
CO	5.76	57.54
VOC	0.38	3.79

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NOx emissions from the respective emission point of each boiler shall not exceed 0.058 lb/MMBtu on a three (3) hour rolling average basis.
- c. PM emissions from the respective emission points of each boiler shall not exceed 1.44 pounds per hour on a 6-hour average basis. Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.
- d. Each boiler shall not exhibit visible emissions from respective emission points greater than 10% opacity on a six (6) minute average basis.

- e. Each boiler shall be fired with refinery fuel gas (RFG) that meets the requirements in Conditions ~~4.1.16~~ and 4.1.17.

Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limits in 45CSR§10-3.1.5 and CO-SIP-95-1 - Condition IV.3.B.b.

- f. Any modifications or replacement of the stacks from Boilers No. A and B shall comply with the provisions of 45CSR20 "Good Engineering Practice as Applicable to Stack Heights".

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§10-3.1.5.; CO-SIP-95-1 - Conditions IV.3.B.b. and IV.10. (SIPed); ~~45CSR16; 40 CFR §60.104(a)(1); and 45CSR13: Permit R13-2334, 4.1.1.]~~

- 4.1.2. 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 Director. 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 Director.

[45CSR§2-4.4.]

- 4.1.3. Boiler C is a “fuel gas combustion device” under Subpart Ja; “fuel burning unit” under 45CSR2 and 45CSR10; and “combusting refinery gas stream” in Section 5 of 45CSR10. The following conditions and requirements are specific to the boiler identified as Boiler C:
~~In the event of an unavoidable shortage of fuel having characteristics or specifications necessary for a fuel burning unit to comply with the visible emission standards set forth in 45CSR§2-3.1. or any emergency situation or condition creating a threat to public safety or welfare, the Director may grant an exception to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during the exception period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the emission standards under 45CSR§2-4.1.b. will not be exceeded during the exemption period.~~

~~**[45CSR§2-10.1. and 45CSR13: Permit R13-2334, 4.1.2.]**~~

- a. The emissions released from Emission Points “Boiler C” shall not exceed following individual emission rates.

Emission Limits for Boiler C		
Pollutant	Emission Rate	
	TPM	TPY
CO	3.43	34.27
VOC	0.22	2.24

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NO_x emissions from Emission Point “Boiler C” shall not exceed 0.050 lb/MMBtu on a three-hour average basis. Boiler C shall be equipped with low NO_x burners.
- c. PM emissions from Emission Point “Boiler C” shall not exceed 0.86 pounds per hour on a 6-hour average basis. Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.
- d. Boiler C shall not exhibit visible emissions from Emission Point “Boiler C” greater than 10% on a six (6) -minute average basis.

- e. The boiler shall either combust natural gas or “fuel gas” that meets the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); and 45CSR13: Permit R13-2334, 4.1.2.]

- 4.1.4. The duct burner for the Combustion Turbine #1 is a “fuel gas combustion device” under Subpart Ja of 40 CFR60 and “fuel burning unit” under 45CSR2 and 45CSR10. The following conditions and requirements are specific to Combustion Turbine #1 with duct burner, which is referred to as TBD01. In the event a fuel burning unit employing a flue gas desulphurization system must by pass such system because of necessary planned or unplanned maintenance, visible emissions may not exceed twenty percent (20%) opacity during such period of maintenance. The Director may require advance notice of necessary planned maintenance, including a description of the necessity of the maintenance activity and its expected duration and may limit the duration of the variance or the amount of the excess opacity exception herein allowed. The Director shall be notified of unplanned maintenance and may limit the duration of the variance or the amount of excess opacity exception allowed during unplanned maintenance. [45CSR§2-10.2. and 45CSR13: Permit R13-2334, 4.1.3.]

- a. Emissions from TBD01 shall not exceed the following:
- i. TBD01 shall not discharge nitrogen oxides (NO_x) emissions in excess of 1.2 lb of NO_x per MWh on a 30-day rolling average basis.
 - ii. TBD01 shall not discharge sulfur dioxide (SO₂) emissions in excess of 0.90 lb of SO₂/MWh on a gross output basis or 0.060 lb of SO₂/MMBtu on a heat input basis.

Compliance with the heat input standard limit shall be satisfied with either current, valid purchase contract, tariff sheet or transportation contract for the natural gas specifying that the maximum total sulfur content for the natural gas is no greater than 20 grains per 100 cubic feet of gas, consuming a gaseous fuel (refinery fuel gas) that does not exceed 0.060 lb SO₂/MMBtu heat input based fuel monitoring outlined in Condition 4.2.12., or combination of these methods for each type of fuel consumed by the turbine.

- b. Mass hourly emissions from Emission Point TDB01 shall not exceed the following limits regardless of the operation of the duct burner:

Emission Limit for Emission Point TDB01		
Pollutant	Emission Rate	
	Hourly Limit (lb/hr)	Annual Limit (TPY)
CO	12.55	56.35
PM ₁₀ /PM _{2.5}	1.81	7.92
VOC	1.50	6.96
Formaldehyde	0.13	0.56
Total HAPs	0.32	1.38

Only the hourly CO and VOC limits in the above table do not apply during startup and shutdown events.

- c. At all times when the duct burner is firing, visible emissions from Emission Point TDB01 shall not be greater than ten (10) percent opacity based on a six-minute average.
- d. At all times when the duct burner is firing, PM emissions from Emission Point TDB01 shall not exceed 1.23 pounds per hour on a 6-hour average basis. *Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.*
- e. Annual mass NO_x emissions from Emission Point TDB01 shall not exceed 39.95 tons per year on a 12-month rolling total basis. This limit shall include NO_x emissions due to the startup events, shutdown events, operating in SoLoNO_xTM mode, operation in non-SoLoNO_xTM mode from the combustion turbine, and NO_x emissions from the duct burner. Any future relaxation of this limit shall only be authorized in accordance with 45CSR14.
- f. The permittee must operate and maintain the 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.

The permittee shall operate TBD01 at a load condition that allows for the operation of the SoLoNO_xTM mode with the Enhanced Emission Control Systems to be engaged at all times except during startup and shutdown events and when ambient air temperatures are below 0 F. The permittee must minimize the time spent during startup and shutdown events which shall not exceed 180 minutes per startup event. Ending/completion of the startup event shall be defined once the CT has reached the 50% load. Once the combustion turbine has successfully started up, the permittee shall in a timely manner increase the loading on the combustion turbine to engage the SoLoNO_xTM mode with the Enhanced Emission Control Systems to minimize emissions. Operating the combustion turbine at idle conditions is not permitted except when transitioning from a successful startup event to a load condition that the SoLoNO_xTM mode can be engaged or when transiting from normal operations with SoLoNO_xTM mode operating to a shutdown event. Monitoring the status of the SoLoNO_xTM operating mode shall be conducted using the parameters with associated operating ranges for the system stated by the turbine manufacture's latest written specifications (e.g., PIL 220).

- g. The duct burner is limited to consuming "fuel gas" meeting the specifications stated in Conditions 4.1.15. and 4.1.17. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*
- h. The maximum amount of energy inputted into the combustion turbine shall not exceed 172 MMBtu/hr on a 24-hour average basis.
- i. The maximum amount of energy input from the duct burner shall not exceed 77.6 MMBtu/hr on a 24-hour average basis.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§§10-3.1.5. & 3.8.; 45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); 40 CFR §60.4320(a), Table 1 to 40 CFR 60 Subpart KKKK, §60.4330(a)(2), §60.4333(a), §60.4365(a), §60.4415(a)(1); and 45CSR13: Permit R13-2334, 4.1.4.]

- 4.1.5. Heater H-101R is a "fuel gas combustion device" under Subpart Ja of 40 CFR 60; and "process heater" under Subpart Ja of 40 CFR 60, 45CSR2 and 45CSR10. The following conditions and requirements are specific to

Heater H-101R for the crude distillation atmospheric heater: ~~Due to unavoidable malfunction of equipment or inadvertent fuel shortages, emissions exceeding those provided for in 45CSR10 may be permitted by the Director for periods not to exceed ten (10) days upon specific application to the Director. Such application shall be made within twenty four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Director provided a corrective program has been submitted by the owner or operator and approved by the Director. [45CSR§10-9.1.]~~

- a. Emissions from Emission Point H-101R shall not exceed the following limits:

<u>Emission Limits for Heater H-101R</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>0.72</u>	<u>7.16</u>
<u>PM₁₀</u>	<u>0.50</u>	<u>1.78</u>
<u>PM_{2.5}</u>	<u>0.50</u>	<u>1.78</u>
<u>VOC</u>	<u>0.12</u>	<u>1.19</u>

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NO_x emissions from the heater shall not exceed 40 ppmv (dry basis, corrected to 0-percent excess air) 30-day rolling average basis. The permittee shall demonstrate compliance with this emission standard by operating this heater in a manner that the daily average O₂ in the heater's exhaust does not exceed the O₂ operating limit or O₂ operating curve determined during the most recent biennial performance test as required in Condition 4.3.1. of this permit.
- c. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii), §60.102a(g)(2)(i)(A), §60.107a(i)(5); and 45CSR13: Permit R13-2334, 4.1.5.]

- 4.1.6. Heater H-102R is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-102R for the CDU Vacuum Heater: ~~The facility shall not burn Fuel Oil in any combustion unit, except during periods of natural gas curtailment and/or during periods of DOT required maintenance of the natural gas pipeline in which the facility shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur). Note: Fuel Oil is defined as any liquid fossil fuel with sulfur content greater than 0.05% by weight.~~
[45CSR13: Permit R13-2334, 4.1.4.]

- a. Emissions from Emission Point H-102R shall not exceed the following limits

<u>Emission Limits for Heater H-102R</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>0.51</u>	<u>5.15</u>
<u>NO_x</u>	<u>1.12</u>	<u>11.16</u>
<u>PM₁₀</u>	<u>0.36</u>	<u>1.28</u>
<u>PM_{2.5}</u>	<u>0.36</u>	<u>1.28</u>
<u>VOC</u>	<u>0.12</u>	<u>0.86</u>

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii);45CSR13: Permit R13-2334, 4.1.6.]

All Boilers and Heaters Except H-201

- 4.1.7. Heater H-201 is a “fuel gas combustion device” under Subpart J of 40 CFR 60; and “process heater” under, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-201 for the
PDR unit. No person shall cause, suffer, allow or permit the discharge of particulate matter into the open
air in excess of the following:

<u>Emission Unit</u>	<u>PM Emission Limit (lbs/hr)</u>
<u>Boiler A</u>	<u>14.36</u>
<u>Boiler B</u>	<u>14.36</u>
<u>Boiler C</u>	<u>8.55</u>
<u>Portable Boiler</u>	<u>8.99</u>
<u>H-101R</u>	<u>4.91</u>
<u>H-102R</u>	<u>3.53</u>
<u>H-500S</u>	<u>5.36</u>
<u>H-501R</u>	<u>1.04</u>
<u>H-600S</u>	<u>3.74</u>
<u>H-441</u>	<u>1.11</u>
<u>H-701</u>	<u>1.09</u>
<u>H-901</u>	<u>2.48</u>
<u>H-1101</u>	<u>3.49</u>

[45CSR§2-4.1.b. and 45CSR13: Permit R13-2334, 4.1.6.]

- a. Emissions from Emission Point H-201 shall not exceed the following limits:

<u>Emission Limits for Heater H-201</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>0.43</u>	<u>2.38</u>

<u>NO_x</u>	<u>0.28</u>	<u>2.78</u>
<u>PM₁₀</u>	<u>0.02</u>	<u>0.22</u>
<u>PM_{2.5}</u>	<u>0.02</u>	<u>0.22</u>
<u>VOC</u>	<u>0.02</u>	<u>0.16</u>

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the fuel requirements and SO₂ lb/mmBtu limit in CO-SIP-95-1 - Condition IV.7.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1);CO-SIP-95-1 - Condition IV.7.; 45CSR13: Permit R13-2334, 4.1.7.]

- 4.1.8. Heater H-441 is a “process heater” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-441 for the Hydrogen Plant: ~~The visible emission standards set forth in 45CSR§2-3 shall apply at all times except in periods of start ups, shutdowns and malfunctions. Where the Director believes that start ups and shutdowns are excessive in duration and/or frequency, the Director may require an owner or operator to provide a written report demonstrating that such frequent start ups and shutdowns are necessary.~~

~~[45CSR§2-9.1. and 45CSR13: Permit R13-2334, 4.1.7.]~~

- a. Emissions from Emission Point H-441 shall not exceed the following limits:

<u>Emission Limits for Heater H-441</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>0.44</u>	<u>4.44</u>
<u>NO_x</u>	<u>0.53</u>	<u>5.28</u>
<u>PM₁₀</u>	<u>0.04</u>	<u>0.40</u>
<u>PM_{2.5}</u>	<u>0.04</u>	<u>0.40</u>
<u>VOC</u>	<u>0.03</u>	<u>0.29</u>

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. This heater shall be limited to firing exclusively on natural gas. Therefore, this heater is exempt from the requirements of subdivision 8.1.1. and subsections 8.2 of 45CSR2; and the requirements of section 8 of 45CSR10.

[46CSR§2-8.4.2.; 45CSR§10-10.3.; 45CSR13: Permit R13-2334, 4.1.8.]

- 4.1.9. Heater H-501R is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-501R ~~for Unifier Charge Heater: At all times, including periods of start-ups, 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 Director which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source. Process heaters H-101R, H-102R, and H-501R shall be equipped with low NO_x burners.~~

~~[45CSR§2-9.2., 45CSR13: Permit R13-2334, 4.1.8., 45CSR16, and 40CFR§60.11(d)]~~

a. [Emissions from Emission Point H-501R shall not exceed the following limits:](#)

Emission Limits for Heater H-501R		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.15	1.50
NO_x	0.33	3.27
PM₁₀	0.04	0.38
PM_{2.5}	0.04	0.38
VOC	0.03	0.25

[TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.](#)

[Annual emission limit – TPY shall be based on 12-month rolling total basis.](#)

b. [The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit.](#)

[\[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a\(g\)\(1\)\(ii\);45CSR13: Permit R13-2334, 4.1.9.\]](#)

- 4.1.10. [Heaters H-502, H-503, H-504, and H-506 under H-500S are “fuel gas combustion devices” under Subpart J of 40 CFR 60; Heater H-505R under H-500S is a “fuel gas combustion device” and “process heater” under Subpart Ja of 40 CFR 60; and all the heaters under H-500S are “process heaters” under 45CSR2, and 45CSR10; The following conditions and requirements are specific to Heater H-500S for the **Unifiner/Platformer unit**: 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 following: the product of 3.1 and the total design heat inputs for such units discharging through those stacks in million BTU's per hour.](#)

~~[45CSR§10-3.1.e. (Boilers A, B, and C, Portable Boiler, Heaters H-101R, H-102R, H-441, H-501R, H-500S, H-600S, H-701, H-901, and H-1101)]~~

a. [Emissions from Emission Point H-500S shall not exceed the following limits:](#)

Emission Limits for Heater H-500S		
Pollutant	Emission Limits	
	TPM	TPY
CO	2.02	20.16
NO_x	2.96	29.58
PM₁₀	0.19	1.80
PM_{2.5}	0.19	1.76
VOC	0.13	1.31

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. Heaters H-502, H-503, H-504, and H-506 shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. *Compliance with this streamlined requirement assures compliance with CO-SIP-1995-1 Section IV.5.*
- c. Heater H-505R shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); 40 CFR §60.102a(g)(1)(ii); CO-SIP-95-1 - Condition IV.5.; and 45CSR13: Permit R13-2334, 4.1.10.]

- 4.1.11. H-600S is a series of four (4) individual heaters venting to common emission point with all four-heaters classified as “fuel gas combustion devices” under Subpart J of 40 CFR 60; and “process heaters” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heaters under H-600S for the **ISOMAX unit**: ~~Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on a continuous twenty four (24) hour averaging time. The owner and/or operator of a fuel burning unit shall not allow emissions to exceed the weight emissions standards for sulfur dioxide as set forth in this rule, except during one (1) continuous twenty four (24) hour period in each calendar month and during this one (1) continuous twenty four hour period said owner and/or operator shall not allow emissions to exceed such weight emission standards by more than ten percent (10%) without causing a violation of this rule. A continuous twenty four (24) hour period is defined as one (1) calendar day.~~ **[45CSR§10 3.8. and 45CSR13: Permit R13-2334, 4.1.9.]**

- a. Emissions from Emission Point H-600S shall not exceed the following limits:

<u>Emission Limits for Heater H-600S</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>1.50</u>	<u>15.01</u>
<u>NO_x</u>	<u>2.14</u>	<u>21.44</u>
<u>PM₁₀</u>	<u>0.14</u>	<u>1.36</u>
<u>PM_{2.5}</u>	<u>0.14</u>	<u>1.36</u>
<u>VOC</u>	<u>0.10</u>	<u>0.98</u>

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. *Compliance with this streamlined requirement assures compliance with CO-SIP-1995-1 Sections IV.5.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); CO-SIP-95-1, Condition IV.5.; 45CSR13: Permit R13-2334, 4.1.11.]

Boilers A, B, and C, Heaters H-201, H-600S, H-701, H-901

- 4.1.12. Heater H-701 is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and a “process heater” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-701 for the VFU: No owner or operator shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The listed heaters and boilers are affected facilities, as that term is used in 40 CFR Part 60 Subparts A and J.

~~[40 CFR §60.104(a)(1) and 45CSR§16 4.1; 45CSR13: Permit R13-2334, 4.1.25.]~~

- a. Emissions from Emission Point H-701 shall not exceed the following limits:

<u>Emission Limits for Heater H-701</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>0.44</u>	<u>4.36</u>
<u>NO_x</u>	<u>0.11</u>	<u>1.06</u>
<u>PM₁₀</u>	<u>0.04</u>	<u>0.39</u>
<u>VOC</u>	<u>0.03</u>	<u>0.29</u>

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall be fired only with natural gas and treated refinery fuel gas. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in CO-SIP-95-1 - Condition IV.6.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); CO-SIP-95-1 - Condition IV.6. (SIPed); 45CSR13: Permit R13-2334, 4.1.12.]

Boilers A, B, and C, Heaters H 101R, H 102R, H 500S, H 501R, H 600S, H 701, H 901

- 4.1.13. Heater H-901 is a “fuel gas combustion device” under Subpart J of 40 CFR 60; and “process heater” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-901 for the DHT Heater: At the request of the Director the owner and/or operator of a source shall install such stack gas monitoring devices as the Director deems necessary to determine compliance with the provisions of 45CSR10. The data from such devices shall be readily available at the source location or such other reasonable location that the Director may specify. At the request of the Director, or his or her duly authorized representative, such data shall be made available for inspection or copying. Failure to promptly provide such data shall constitute a violation of this rule.

~~[45CSR§10 8.2.a. and 45CSR13: Permit R13-2334, 4.1.10.]~~

- a. Emissions from Emission Point H-901 shall not exceed the following limits:

<u>Emission Limits for Heater H-901</u>		
<u>Pollutant</u>	<u>Emission Limits</u>	
	<u>TPM</u>	<u>TPY</u>
<u>CO</u>	<u>0.42</u>	<u>4.22</u>
<u>NO_x</u>	<u>0.30</u>	<u>3.01</u>

<u>PM₁₀</u>	<u>0.08</u>	<u>0.79</u>
<u>PM_{2.5}</u>	<u>0.08</u>	<u>0.79</u>
<u>VOC</u>	<u>0.12</u>	<u>1.20</u>

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); 45CSR13: Permit R13-2334, 4.1.13.]

Boilers A and B

- 4.1.14. Heater H-1101 is a “indirect heat exchanger” under Subpart Dc of 40 CFR60; and a “**Fuel Burning Unit**” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-1101 for the hydrogen plant: ~~The combined emissions from Boiler A and Boiler B (Emission Point ID Nos. A & B, which is a common stack) shall not exceed those listed below. NO_x limits (based on a three hour averaging period) for each boiler shall be as follows: Boiler A – 0.058 lb/MMBtu and Boiler B – 0.058 lb/MMBtu.~~

- a. Emissions from Emission Point H-1101 shall not exceed the following limits:

<u>Emission Limits for Heater H-1101</u>		
Pollutant	Emission Limits	
	~~Tons per month (TPM)~~	Tons per year (TPY)
CO	<u>0.17</u> ~~11.51~~	<u>1.70</u> ~~115.07~~
NO _x	<u>0.68</u> ~~8.1~~	<u>6.80</u> ~~81.04~~
~~PM~~	~~1.04~~	~~10.42~~
~~SO₂~~	~~0.81~~	~~8.06~~
<u>PM₁₀</u>	<u>0.17</u>	<u>1.70</u>
<u>PM_{2.5}</u>	<u>0.17</u>	<u>1.70</u>
VOC	<u>0.13</u> ~~0.75~~	<u>1.25</u> ~~7.53~~

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.

Annual emission limit – TPY shall be based on 12-month rolling total basis.

[45CSR13: Permit R13-2334, 4.1.13.]

- b. PM emissions from the Emission Point “H-1101” shall not exceed 0.47 pound per hour on a 6-hour average basis. *Compliance with this streamlined PM limit will ensure compliance with 45CSR§2-4.1.2.*
- c. Heater H-1101 shall not exhibit visible emissions from Emission Point “H-1101” greater than 10% on a six (6) -minute average basis.
- d. This heater shall be limited to firing exclusively on natural gas. Therefore, this heater is exempt from the requirements of subdivision 8.1.1. and subsections 8.2 of 45CSR2; and the requirements of section 8 of 45CSR10.
- e. SO₂ emissions from the Emission Point “H-1101” shall not exceed 120.28 pound per hour.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§2-8.4.2.; 45CSR§10-3.1.5.; 45CSR§10-10.3; 45CSR13: Permit R13-2334, 4.1.14.]

- 4.1.15. a. The permittee shall not allow any “fuel gas combustion device” to burn any “refinery fuel gas” (RFG) that contains hydrogen sulfide (H₂S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. ~~Emissions from the operation of Boilers A & B, shall not exceed a total emission rate of 264 lbs. SO₂/hr.~~

~~[CO-SIP 95-1 Condition IV.3.B.b. (SIPed)]~~

- b. For each exceedance of the 162 ppm H₂S standard in the above paragraph that results in a SO₂ discharge from a “fuel gas combustion device” subject to this standard greater than 500 pounds than the amount that would be if the H₂S emissions standard had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter. Then, the permittee shall conduct a “root cause analysis” and “corrective action analysis” as soon as possible, but no later than 45 days after such exceedance and implement “corrective action” in accordance with 40 CFR §60.103a(e) if applicable.

- c. The corrective action(s) identified in the corrective action analysis conducted pursuant to 40 CFR §60.103a(d) shall be implemented in accordance with the applicable requirements in 40 CFR §60.103a(e)(1) through (3) as follows:

- i. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in 40 CFR §60.108a(c)(6)(ix).
- ii. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.
- iii. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in 40 CFR §60.108a(c)(6)(x).

[45CSR16; 40 CFR §102a(g)(1)(ii), §§60.103a(c) & (c)(2), §60.103a(d), §60.103a(e); 45CSR13: Permit R13-2334, 4.1.15.]

- 4.1.16. The permittee shall not allow any “fuel gas combustion device” to burn any “fuel gas” that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 grains/dscf) determined hourly on a 3-hour rolling average basis. ~~Any modifications or replacement of the stacks from Boilers No. A and B shall comply with the provisions of 45CSR20 "Good Engineering Practice as Applicable to Stack Heights".~~

~~[CO-SIP 95-1 Condition IV.10. (SIPed)]~~

[45CSR6; 40 CFR §60.104(a)(1), §60.105(e)(3)(ii); 45CSR13: Permit R13-2334, 4.1.16.]

Boiler-C

- 4.1.17. [The permittee shall not combust any refinery fuel gas \(refinery process gas\) stream that contains hydrogen sulfide in a concentration greater than 50 grains per 100 cubic feet of gas. Compliance with this hydrogen sulfide concentration limit shall be based on 3-hour block averaging time. ~~Boiler C shall be equipped with low NO_x burners. NO_x limits \(based on a three hour averaging period\) shall be 0.050 lb/MMBTU. Emissions from Boiler C \(Emission Point ID No. C\) shall not exceed the limits in the following table. Compliance with the NO_x limit shall demonstrate compliance with the less stringent limit of Permit R13-2334. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.~~](#)

Pollutant	Emission limit	
	Tons per month (TPM)	Tons per year (TPY)
CO	3.43	34.27
NO _x	2.08	20.81
PM	0.31	3.1
SO ₂	0.24	2.41
VOC	0.22	2.24

~~[45CSR13: Permit R13-2334, 4.1.14., 4.1.15.; 45CSR§10-3.1.e.]~~

[\[45CSR§§10-5.1 and 5.4.; 45CSR13: Permit R13-2334, 4.1.17.\]](#)

~~Heaters H-101R, H-102R, and H-501R~~

- 4.1.18. [At all times, including periods of start-ups, shutdowns and malfunctions, the permittee shall, to the extent practicable, maintain and operate any of the permittee “fuel burning unit\(s\)” Boilers A, B, and C; duct burner for TDB01; and H-1101; “fuel gas combustion devices,” and “process heaters,” 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 Director and/or Administrator which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source. ~~Process heaters H-101R, H-102R, and H-501R shall be equipped with low NO_x burners. NO_x limits \(determined daily on a 30-day rolling averaging basis\) on H-101R shall be 40ppmv \(dry basis, corrected to 0 percent excess air\). Combined emissions from H-101R and H-102R, and emissions from H-501R shall not exceed those listed below.~~](#)

Pollutant	H-101R and H-102R		H-501R	
	TPM	TPY	TPM	TPY
CO	1.23	12.31	0.15	1.5
NO _x	2.67	26.68	0.33	3.27
PM _{2.5}	0.86	3.06	0.04	0.35
PM ₁₀	0.86	3.06	0.04	0.35
PM	0.86	3.06	0.04	0.38
SO ₂	1.09	10.88	0.11	1.12
VOC	0.21	2.05	0.03	0.25

~~[45CSR13: Permit R13-2334, 4.1.15., 4.1.16, 45CSR16, 40 CFR §60.102a(g)(2)(i)(A)]~~

[\[45CSR§2-9.2., 45CSR13: Permit R13-2334, 4.1.18., 45CSR16, and 40 CFR §60.11\(d\)\]](#)

Heaters H 201, H 441, and H 701

4.1.19. [The conditions and requirements in the following subdivisions are specific to the Fluid Cooler \(ID CCT01\):](#)
~~Emissions from heaters H 201, H 701, and H 441 shall not exceed those listed in the following table.~~
~~Compliance with the SO₂ limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.~~

- a. [Emissions of PM, PM-10, and PM_{2.5} shall be controlled with a 0.001% of the recirculating water rate drift eliminator or equivalent control technology.](#)
- i. [PM emissions emitted to the atmosphere from the Fluid Cooler shall not exceed 0.19 lb/hr and 0.82 TPY.](#)
- ii. [PM₁₀ and PM_{2.5} emissions emitted to the atmosphere from the Fluid Cooler shall not exceed 0.01 lb/hr and 0.01 TPY.](#)
- b. [Make-up water for the Fluid Cooler shall not have a total dissolved solids concentration greater than 18,500 ppmw at any time.](#)

Pollutant	H-201		H-701		H-441	
	TPM	TPY	TPM	TPY	TPM	TPY
CO	0.43	2.38	0.44	4.36	0.44	4.44
NO _x	0.28	2.78	0.11	1.06	0.53	5.28
PM	0.02	0.22	0.04	0.39	0.04	0.40
SO ₂	0.08	0.77	0.14	1.4	0.01	0.03
VOC	0.02	0.16	0.03	0.29	0.03	0.29

~~[45CSR13: Permit R13-2334, 4.1.20., 45CSR§10-3.1.e.]~~

[\[45CSR13: Permit R13-2334, 4.1.19.\]](#)

~~4.1.20. Heater H 441 shall be limited to combusting natural gas only.~~

~~[CO SIP 95-1 Condition IV.8. (SIPed); 45CSR13: Permit R13-2334, 4.1.21.]~~

~~4.1.21. The vacuum fractionator heater, H 701, shall be fired only with natural gas and/or treated refinery fuel gas that contains hydrogen sulfide in a concentration not to exceed 10 grains/100 dry standard cubic feet of gas, and emissions of sulfur dioxide shall not exceed 0.8 lbs/mmBtu.~~

~~[CO SIP 95-1 Condition IV.6. (SIPed)]~~

Heaters H 500S and H 600S

~~4.1.22. Emissions from H 500S and H 600S heaters shall not exceed those listed in the following table. Note: “S” means multiple heaters with emissions exiting a common emission point.~~

Pollutant	H-500S	H-600S

	TPM	TPY	TPM	TPY
CO	2.02	20.16	1.5	15.01
NO _x	2.96	29.58	2.14	21.44
PM _{2.5}	0.18	1.76	n/a	n/a
PM ₁₀	0.18	1.80	n/a	n/a
PM	0.19	1.90	0.14	1.36
SO ₂	0.72	7.21	0.48	4.83
VOG	0.13	1.31	0.1	0.98

~~[45CSR13: Permit R13-2334, 4.1.22.]~~

Heaters H-901 and H-1101

4.1.23. Emissions from the DHT Heater (H-901) and Hydrogen Plant Heater (H-1101) shall not exceed those listed in the following table.

Pollutant	H-901		H-1101	
	TPM	TPY	TPM	TPY
CO	0.42	4.22	0.17	1.70
NO _x	0.30	3.01	0.68	6.80
PM	0.08	0.79	0.17	1.70
SO ₂	0.27	2.72	0.01	0.10
VOG	0.12	1.20	0.13	1.25

~~[45CSR13: Permit R13-2334, 4.1.23.]~~

4.1.24. Heater H-1101 shall be limited to combusting natural gas only.

~~[45CSR13: Permit R13-2334, 4.1.24.]~~

Boilers A, B, and C, Heaters H-201, H-500S, H-600S, H-701, and H-901

4.1.25. The permittee shall comply with the emission limitations set forth in 40 CFR 60 Subpart J on and after the date on which the initial performance test, required by 40 CFR § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

~~[40 CFR § 60.104, 45CSR§16 4.1; 45CSR13: Permit R13-2334, 4.1.26.]~~

Heaters H-101R, H-102R, H-500S, and H-501R

4.1.26. The permittee shall comply with the emission limitations set forth below on and after the date on which the initial performance test, required by 40 CFR §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

~~[45CSR16, 40 CFR §§ 60.102a (a) and (g)(1)(ii), 45CSR13: R13-2334, 4.1.17.]~~

- ~~4.1.27. c. Each owner or operator that operates a fuel gas combustion device subject to 40 CFR Part 60 Subpart Ja shall conduct a root cause analysis and a corrective action analysis for the following condition specified in 40 CFR §§ 60.103a (c) (2):~~

~~For a fuel gas combustion device, each exceedance of an applicable short term emissions limit in 40 CFR § 60.102a (g) (1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24 hour period, whichever is shorter.~~

- ~~d. A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3). Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 40 CFR §§ 60.103a (d) (1):~~

~~1. If a single continuous discharge meets any of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3) for 2 or more consecutive 24 hour periods, a single root cause analysis and corrective action analysis may be conducted.~~

~~5. If discharges occur that meet any of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3) for more than one affected facility in the same 24 hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.~~

- ~~e. The owner or operator of a fuel gas combustion device subject to 40 CFR Part 60 Subpart Ja shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to 40 CFR § 60.103a (d) in accordance with the applicable requirements in 40 CFR §§ 60.103a (e) (1) through (3):~~

~~1. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If permittee concludes that corrective action should not be conducted, the permittee shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in 40 CFR § 60.108a (e) (6) (ix).~~

~~2. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the permittee shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.~~

~~3. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the permittee shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in 40 CFR § 60.108a (e) (6) (x).~~

- ~~j. *Alternative means of emission limitation.*~~

~~1. Each permittee subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in~~

~~emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in 40 CFR § 60.103a.~~

- ~~2. Determination of equivalence to the design, equipment, work practice or operational requirements of 40 CFR § 60.103a will be evaluated by the following guidelines:~~
 - ~~i. Each permittee applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.~~
 - ~~ii. For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.~~
 - ~~iii. For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.~~
 - ~~iv. Each permittee applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.~~
 - ~~v. The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in 40 CFR § 60.103a (j) (2) (iv).~~
 - ~~vi. The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.~~
- ~~3. A permittee may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.~~
- ~~4. Approval of the application for equivalence to the design, equipment, work practice or operational requirements of 40 CFR § 60.103a will be evaluated by the following guidelines:~~
 - ~~i. After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.~~
 - ~~ii. After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.~~
 - ~~iii. Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h) (1) of the CAA.~~

~~5. Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of 40 CFR § 60.103a. The Administrator will make an equivalence determination according to the provisions of 40 CFR §§ 60.103a (j) (2) through (4).~~

~~[45CSR16, 40 CFR § 60.103a(c)(2), (d)(1), (d)(5), (e), and (j), 45CSR13: R13-2334, 4.1.18.]~~

Portable Boiler

4.1.20. ~~4.1.28.~~ Emissions from the Portable Boiler shall not exceed the following:

CO		NO _x		PM		SO ₂		VOCs		HAPs	
lb/hr	tpy	lb/hr	tpy	lb/hr*	tpy	lb/hr*	tpy	lb/hr	tpy	lb/hr	tpy
8.23	11.06	4.90	6.58	0.74	1.00	0.06	0.08	0.54	0.72	0.01	0.02

** Compliance with these streamlined PM and SO₂ lb/hr limits will ensure compliance with 45CSR§2-4.1.2. and 45CSR§10-3.1.5. respectively.*

~~[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13: R13-2334, 4.1.3.a. 4.1.27.]~~

4.1.21. ~~4.1.29.~~ The portable boiler shall burn pipeline quality natural gas only.

~~[45CSR13: R13-2334, 4.1.3.b. 4.1.28.]~~

4.1.22. ~~4.1.30.~~ The portable boiler shall only operate at the following times:

- i. When either Boilers A, B or C are offline; ~~or~~
- ii. Prior to the shutdown of Boiler A, B, or C only while the portable boiler is in startup mode; or
- iii. When Boiler A, B, or C is in startup mode.

~~[45CSR13: R13-2334, 4.1.3.c. 4.1.29.]~~

4.1.23. ~~4.1.31.~~ The portable boiler shall not operate more than 2,688 hours per year. Compliance with this condition shall be based on a 12 month rolling total.

~~[45CSR13: R13-2334, 4.1.3.d. 4.1.30.]~~

4.1.24. ~~4.1.32.~~ The portable boiler shall not be attached to a foundation and shall not be onsite for more than 180 consecutive days.

~~[45CSR13: R13-2334, 4.1.3.e. 4.1.31.]~~

4.1.25. 180 days after the initial startup of TBD01 (combustion turbine w/duct burner), the permittee shall no longer be authorized to bring on site and operate a portable boiler under this permit.

~~[45CSR13: R13-2334, 4.1.3.f.]~~

4.2. Monitoring Requirements

All Boilers and Heaters

- 4.2.1. [For the purpose of verifying compliance for the boilers and heaters, which has been identified in Section 4.1. that is subject to the opacity limits of 45CSR§2-3.1, the permittee shall conduct visible emission checks and/or opacity monitoring and recordkeeping in accordance with the following.](#) ~~Visual emission checks of each emission point subject to an opacity limit shall be conducted during periods of facility operation for a sufficient time interval to determine if the unit has visible emissions using 40 CFR 60 Appendix A, Method 22. If natural gas is being combusted, the visual emissions checks shall be conducted monthly. If fuel oil is being combusted, the visual emissions checks shall be conducted weekly. If visible emissions are identified during the survey, or at any other time, the permittee shall take corrective action to minimize the emissions immediately. If during these checks, or at any other time, visible emissions are observed, a visible emission evaluation shall be conducted in accordance with 40 CFR 60 Appendix A, Method 9. A Method 9 evaluation shall not be required if the visible emission condition is corrected in a timely manner. A record of each visible emission check required above shall be maintained on site for a period of no less than five (5) years. Said record shall include, but not be limited to, the date, time, name of emission unit, the applicable visible emissions requirement, the results of the check, what action(s), if any, was/were taken, the name of the observer, and any data required by 40 CFR 60 Appendix A, Method 22 or Method 9.~~
- a. [The visible emission check shall determine the presence or absence of visible emissions. 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 Part 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR Part 60, Appendix A, Method 9 certification course.](#)
- b. [Visible emission checks shall be conducted at least once per calendar year of the respective emission point for Boilers A, B, and C. These checks shall be performed at each source \(stack, transfer point, fugitive emission source, etc.\) for a sufficient time interval, but no less than six \(6\) minutes, to determine if any visible emissions are present. Visible emission checks shall be performed during periods of normal facility operation and appropriate weather conditions.](#)
- c. [If visible emissions are present at a source\(s\) during the visible emission check, the permittee shall conduct an opacity reading at that source\(s\) using the procedures and requirements of U.S. EPA Method 9 as soon as practicable, but within seventy-two \(72\) hours of the visual emission check that detected visible emissions. Records of such checks and Method 9 observations shall be maintained in accordance with Condition 3.4.2 of this permit.](#)

[45CSR13:- Permit R13-2334, 4.2.1.]

~~Boilers A and B, All Heaters (except H-101R, H-102R, H-501R, H-901 and H-1101)~~

- 4.2.2. [For Boilers A and B, All Heaters \(except H-101R, H-102R, H-501R, H-901 and H-1101\):](#) Compliance with the emission limitations of CO-SIP-95-1 shall be based upon the averaging time and compliance determination methods established within [Section V of CO-SIP-95-1](#) ~~in Sections 4.2.4. through 4.2.7., and 4.2.10. of this permit.~~

[CO-SIP-95-1 - Condition V.1. (SIPed)]

Boilers A and B

- 4.2.3. [For Boilers A and B:](#) The permittee shall monitor compliance with 45CSR§2-3 in an approved monitoring plan (see Appendix A) for each emission unit. Such plans shall include, but not be limited to, one or more

of the following: continuous measurement of emissions, monitoring of emission control equipment, periodic parametric monitoring, or such other monitoring as approved by the Director.

[45CSR§2-8.2.; ~~45CSR13: Permit R13-2334, 4.1.12.~~]

4.2.4. The permittee shall monitor O₂ of the exhaust from Heater H-101R as alternative to monitoring NO_x emissions as allowed under Subpart Ja of 40 CFR60 for natural draft process heater with a heat input between 40 to 100 MMBtu/hr in accordance with the following requirements for the purpose of demonstrating compliance with Condition 4.1.5.b. of this permit: ~~Compliance with the sulfur dioxide emission limitations established in Section 4.1.15. for gas-fired boiler Nos. A and B shall be demonstrated in accordance with the following provisions:~~

- a. The permittee shall install, operate, and maintain O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.
- b. The permittee shall conduct performance evaluations of each O₂ monitor according to the requirements in 40 CFR §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to 40 CFR60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.
- c. The permittee shall comply with the quality assurance requirements in Procedure 1 of appendix F to 40 CFR60 for each O₂ monitor, including annual accuracy determinations for O₂ monitors, and daily calibration drift tests.
- d. For Heater H-101R, the permittee shall determine excess NO_x emissions as each day during which the concentration of O₂ as measured by the O₂ continuous monitoring system required under this condition exceeds the O₂ operating limit or operating curve determined during the most recent biennial performance test as required in Condition 4.3.1. of this permit.
- e. The permittee shall maintain records of the measured readings, performance evaluations, annual accuracy determinations, daily calibration drift tests and any maintenance performed on the monitoring system/instrument in accordance with Condition 3.4.2. of this permit.

~~a. Co-located continuous monitoring systems (for sulfur dioxide and oxygen) shall be installed, calibrated, maintained and operated to measure the concentration of sulfur dioxide and oxygen in the combustion gases discharged from these boilers. The continuous monitoring systems and programs shall comply with the requirements of Sections 4.2.5. and 4.2.6.~~

~~b. Following installation of the continuous monitoring system, compliance shall be determined based upon a rolling three (3) hour average of measured sulfur dioxide concentrations and procedures approved by the Director to calculate hourly mass emissions.~~

~~c. During any period after June 1, 1995 in which either of these boilers is operated without its continuous emission monitoring system in proper operation, the Company shall fire only natural gas or desulfurized refinery fuel gas in the boiler.~~

[~~CO-SIP 95-1 Condition V.3. (SIPed) (During fuel oil combustion only, see Section 4.1.6.)~~]

[45CSR16; 40 CFR §§60.107a(c), (c)(3) – (c)(5) and (i)(5); 45CSR13: Permit R13-2334, 4.2.4.]

~~4.2.5. Installation, calibration, maintenance and operation of the continuous emission monitoring systems required under Section 4.2.4., shall comply with the following provisions under 40 CFR Part 60:~~

~~a. Part 60.13(a)~~	~~i. Part 60.13(j)~~
~~b. Part 60.13(e)~~	~~j. Part 60.45(e)~~
~~c. Part 60.13(d)(1)~~	~~k. Part 60.45(e)~~
~~d. Part 60.13(e)(2)~~	~~l. Part 60.45(f)~~
~~e. Part 60.13(f)~~	~~m. Part 60.46(b)(4)~~
~~f. Part 60.13(g)~~	~~n. Part 60; Appendix A, Methods 6, 6A and 6B~~
~~g. Part 60.13(h)~~	~~o. Part 60; Appendix B, Performance Specification 2~~
~~h. Part 60.13(i)~~	~~p. Part 60; Appendix B, Performance Specification 3~~

Where the term “Administrator” (USEPA) is used within any of the adopted 40 CFR Part 60 provisions, the term shall mean the Director.

~~[CO-SIP-95-1 Condition V.5. (SIPed)]~~

~~4.2.6. All continuous emission monitoring data required to be collected under Section 4.2.4. shall be quality assured in accordance with 40CFR part 60, Appendix F Quality Assurance Procedures.~~

~~[CO-SIP-95-1 Condition V.7. (SIPed)]~~

Boilers A and B, Heaters H-701, H-500S, H-600S

~~4.2.5.~~ ~~4.2.7.~~ Sources of sulfur dioxide emissions subject to CO-SIP-95-1 shall demonstrate compliance with the emission standards set forth in [subsections IV .3, IV .4, IV .5, IV .6, IV .7, IV .9 and IV .10 of CO-SIP-95-1](#) [Sections 4.1.15., 4.1.21., and 5.1.5.](#), using data collected in accordance with ~~this~~ [section V. of CO-SIP-95-1](#) and reference emissions test procedures in 40 CFR Part 60, Appendix A, Methods 6, 6A, 6B, and 19.

~~[CO-SIP-95-1 - Condition V.8. (SIPed)]~~

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701, H-901

~~4.2.8.~~ The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) shall demonstrate compliance with sections 3, 4 and 5 of 45CSR10 by testing and /or monitoring in accordance with one or more of the following: 40 CFR Part 60, Appendix A, Method 6, Method 15, continuous emissions monitoring systems (CEMS) or fuel sampling and analysis as set forth in an approved monitoring plan for each emission unit (see Appendix A).

~~[45CSR§10-8.2.c.; 45CSR13: Permit R13-2334, 4.1.11.]~~

Boilers A, B, and C, Heaters H-201, H-600S, H-701, H-901

~~4.2.6.~~ ~~4.2.9.~~ To demonstrate compliance with Conditions [4.1.15., 4.1.16., and 4.1.17.](#), the permittee shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

To demonstrate compliance with Section [4.1.12](#), the permittee shall install, certify, calibrate, maintain, and operate a fuel gas CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B.

- a. This instrument shall be installed, operated, and maintained according to Performance Specification 7 to 40 CFR60. The span value for this instrument is 300 ppmv H₂S. *Compliance with this streamlined span value of 300 ppmv H₂S will ensure compliance with 40 CFR §60.105(a)(4)(i).*

During any period of failure or malfunction of the H₂S monitor system, the permittee shall collect two (2) gas samples of the RFG per eight (8) hour period and determine the H₂S concentration and heating value of each sample through a gas chromatography in accordance with ASTM Method D-1945. The permittee may request approval by the Director of alternative sampling and analytical methods for determination of these parameters during periods when the H₂S monitoring system has failed or malfunctioned.

- b. The permittee shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR§60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to 40 CFR60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see 40 CFR§60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to 40 CFR60.
- c. The permittee shall comply with the applicable quality assurance procedures in appendix F to 40 CFR60 for each H₂S monitor.
- d. Fuel gas combustion devices or flares 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 fuel gas combustion devices or flares.
- e. For the duct burner for the combustion turbine; Boiler C and Heaters H-101R, H-102R, H-501R, H-505R, and H-701, the permittee shall determine excess the arithmetic average of each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under this condition exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under this condition exceeds 60 ppmv.
- f. For ~~Boiler A, Boiler B; and~~ Heaters H-201, ~~H-500S (excluding H-505R),~~ H-600S and H-901, the permittee shall determine excess the arithmetic average of all three (3) hour averages during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under this condition exceeds 230 mg/dscm (0.10 gr/dscf).
- g. For Boilers A, B, and C; duct burner for the combustion turbine; and Heaters H-101R, H-102R, H-201, H-501R, H-500S, H-600S, H-701, and H-901, the permittee shall determine each 3-hour block average exceeds 50 grains per 100 scf of gas if there are excess emission identified from paragraphs e. (3-hour standard) or f. of this condition.
- h. For any periods that the excess emissions are determined of the short term (3-hour average) average standards under paragraphs e. and/or f. of this condition, the permittee shall determine the daily SO₂ emissions in terms of lb of SO₂ per hour for Boilers A and B, and lb of SO₂ per MMBtu for Heater H-201, H-500S, H-600S, and H-701 to determine compliance the SO₂ limits of Consent Order CO-SIP-95-1.

All valid hourly readings shall be reduced into 3-hour averages. Records of all readings, maintenance performed, calibrations, and audits shall be maintained in accordance with Condition 3.4.2. of this permit.

~~Compliance with the hydrogen sulfide concentration limit of permit condition 4.1.12. shall be demonstrated using the continuous monitor as follows:~~

- ~~a. An instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.~~
- ~~i. The span value for this instrument is 425 mg/dscm H₂S.~~
- ~~ii. Fuel gas combustion devices 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.~~
- ~~iii. The performance evaluations for this H₂S monitor under 40 CFR § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations~~

Compliance with this condition will ensure ~~shall demonstrate~~ compliance with CO-SIP-95-1, Conditions V.3., V.4., V.5., and V.6.

[45CSR16; 40 CFR §§60.7(f), (f)(1) and (f)(2), §§60.105(a)(4)(i), (ii), and (iii), 60.105(e)(3)(ii), §§60.107a(a)(2)(i)-(iv), §60.107a(i)(1)(ii); and ~~45CSR§16-4.1; 45CSR§10-5.4. and §§10-8.2.3., 8.2.3.a., 8.2.3.a.1.;~~ CO-SIP-95-1 - Conditions V.3. V.4., V.5., V.6., V7 and V.11. (SIPed); 45CSR13: Permit R13-2334, 4.2.2., ~~4.2.4.~~]

~~Heaters H-201, H-500S, H-600S~~

~~4.2.10. Compliance with the sulfur dioxide emission limitations established in Sections 4.4.12. and 4.4.14. for Process Heater H-201, H-500S, and H-600S shall be determined daily in accordance with the following provisions:~~

- ~~a. Total daily sulfur dioxide emissions for each heater shall be calculated by adding the sulfur dioxide emissions attributable to each fuel fired during all twenty-four (24) hour periods.~~
- ~~b. Sulfur dioxide emissions attributable to the combustion of fuel oil shall be determined by sampling and analyzing the volume of fuel oil fired for sulfur content and heating volume in accordance with applicable ASTM sampling and analytical methods and accurately measuring the volume and mass of fuel oil fired in each heater.~~

~~[CO-SIP-95-1 – Condition V.4. (SIPed) (During fuel oil combustion only, see Section 4.1.6.)]~~

~~Heaters H-901 and H-1101~~

4.2.7. ~~4.2.11.~~ The permittee shall monitor and record the amount of fuel gas consumed in Heaters H-101R, H-102R, H-201, H-501R, H-500S, H-600S, H-701, H-901 and duct burner for TDB01 through individual volumetric flow meters. Records of the readings, maintenance performed on the instruments, and calibrations shall be maintained in accordance with Condition 3.4.2. of this permit. ~~using flow meters.~~

[45CSR13: Permit R13-2334, 4.2.6.; CO-SIP-95-1 - Condition V.4. (SIPed)]

~~4.2.8.~~ ~~4.2.12.~~ The permittee shall monitor [and record](#) the amount of natural gas consumed [in heaters H-441 and H-1101](#) using flow meters. [Records of the readings, maintenance performed on the instruments, and calibrations of the instruments shall be maintained in accordance with Condition 3.4.2. of this permit.](#)

[45CSR13: Permit R13-2334, 4.2.5.]

Boilers A and B

~~4.2.9.~~ ~~4.2.13.~~ To demonstrate compliance with the three-hour average NO_x limit of Section [4.1.1.b.](#) ~~4.1.14.~~, the permittee shall install, certify, calibrate, maintain, and operate a CEMS on Boilers A and B to measure NO_x and O₂ in accordance with the requirements of 40 CFR §60.11, 60.13, and 40 CFR Part 60 Appendices A and F.

[45CSR13: Permit R13-2334, 4.2.3.]

Heaters H-101R, H-102R, H-500S, and H-501R

~~4.2.14. a. — Fuel gas combustion devices subject to H₂S limit.~~

~~The owner or operator of a fuel gas combustion device that is subject to 40 CFR § 60.102a(g)(1) and elects to comply with the H₂S concentration limits in 40 CFR § 60.102a(g)(1)(ii) shall comply with 40 CFR § 60.107a (a)(2).~~

~~2. — The owner or operator of a fuel gas combustion device that elects to comply with the H₂S concentration limits in 40 CFR § 60.102a (g) (1) (ii) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device.~~

~~i. — The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of 40 CFR Part 60 Appendix B. The span value for this instrument is 300 ppmv H₂S.~~

~~ii. — The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR § 60.13 (c) and Performance Specification 7 of 40 CFR Part 60 Appendix B. The owner or operator shall use Method 11, 15, or 15A of 40 CFR Part 60 Appendix A 5 or Method 16 of 40 CFR Part 60 Appendix A 6 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10 1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference — see 40 CFR § 60.17) is an acceptable alternative to EPA Method 15A of 40 CFR Part 60 Appendix A 5.~~

~~iii. — The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR Part 60 Appendix F 60 for each H₂S monitor.~~

~~iv. — Fuel gas combustion devices 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 fuel gas combustion devices.~~

~~d. — Process heaters complying with the NO_x heating value based or mass based limit.~~

~~The owner or operator of a process heater subject to the NO_x emissions limit in 40 CFR § 60.102a (g) (2) and electing to comply with the applicable emissions limit in 40 CFR § 60.102a (g)(2)(i)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in 40 CFR §§ 60.107a (d)(1) through (4).~~

- ~~1. Except as provided in 40 CFR § 60.107a (d)(8), the owner or operator shall install, operate and maintain each NO_x monitor according to the requirements in 40 CFR §§ 60.107a (c) (1) through (5). The monitor must include an O₂ monitor for correcting the data for excess air.~~
- ~~2. Except as provided in 40 CFR § 60.107a (d)(3), the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of Appendix A 7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).~~
- ~~3. As an alternative to the requirements in 40 CFR § 60.107a (d)(2), the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of 40 CFR Part 60 Subpart Ja and Equation 10 of 40 CFR § 60.107a. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).~~

$$F_d = \frac{1,000,000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)}$$

~~Where:~~

- ~~F_d = F factor on dry basis at 0 percent excess air, dscf/MMBtu.~~
~~X_i = mole or volume fraction of each component in the fuel gas.~~
~~MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).~~
~~MHC_i = molar heat content, Btu per mole (Btu/mol).~~
~~1,000,000 = unit conversion, Btu per MMBtu.~~

- ~~4. The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of 40 CFR Part 60 Appendix B. Any of the following methods shall be used for conducting the relative accuracy evaluations:~~
 - ~~i. EPA Method 18 of 40 CFR Appendix A 6;~~
 - ~~ii. ASTM D1945-03 (Reapproved 2010) (incorporated by reference see 40 CFR § 60.17);~~
 - ~~iii. ASTM D1946-90 (Reapproved 2006) (incorporated by reference see 40 CFR § 60.17);~~
 - ~~iv. ASTM D6420-99 (Reapproved 2004) (incorporated by reference see 40 CFR § 60.17);~~
 - ~~v. GPA 2261-00 (incorporated by reference see 40 CFR § 60.17); or~~
 - ~~vi. ASTM UOP539-97 (incorporated by reference see 40 CFR § 60.17).~~

- i. ~~Excess emissions.~~

~~For the purpose of reports required by § 40 CFR § 60.7 (c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in 40 CFR § 60.102a (g) are defined as specified in 40 CFR §§ 60.107a (i) (1) through (5). Determine a rolling 3 hour or a rolling daily average as the arithmetic average of the applicable 1 hour averages (e.g., a rolling 3 hour average is the arithmetic average of three contiguous 1 hour averages). Determine a rolling 30 day or a rolling 365 day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30 day average is the arithmetic average of 30 contiguous daily averages).~~

- ~~1. H₂S limits for fuel gas combustion devices. ii. If the owner or operator of a fuel gas combustion device elects to comply with the H₂S concentration limits in 40 CFR § 60.107a § 60.102a (g) (1) (ii), each rolling 3 hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under 40 CFR § 60.107a (a) (2) exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under 40 CFR § 60.107a (a) (2) exceeds 60 ppmv.~~
- ~~3. Rolling 30 day average NO_x limits for fuel gas combustion devices. Each rolling 30 day period during which the average concentration of NO_x as measured by the NO_x continuous monitoring system required under 40 CFR § 60.107a (c) or (d):~~
 - ~~i. For a natural draft process heater, 40 ppmv and, if monitored according to 40 CFR § 60.107a (d), 0.040 lb/MMBtu;~~

~~[45CSR16, 40 CFR §§ 60.107a(a)(2)(i) through (iv), (d)(1) through (4), (i)(1)(ii), and (i)(3)(i), 45CSR13: R13-2334, 4.2.7.]~~

Portable Boiler

4.2.10. ~~4.2.15.~~ To demonstrate compliance with the requirements of 4.1.23, ~~4.1.31~~, the permittee shall monitor the number of hours of operation of the Portable Boiler on a monthly basis.
~~[45CSR13: R13-2334, 4.2.7, 4.2.8.]~~

4.2.11. To demonstrate compliance with the NO_x emission limits of Conditions 4.1.4.a.i. and 4.1.4.f., the permittee shall install, certify, calibrate, maintain, and operate a CEMS to determine NO_x emissions from the combustion turbine with duct burner accordance with the following requirements.

- a. Each NO_x diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. Alternatively, a NO_x diluent CEMS that is installed and certified according to appendix A of 40 CF 75 is acceptable for use under 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 for each type of fuel shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to 40 CFR 75 are acceptable for use under this condition.
- 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. For the determination of mass NO_x emissions, the permittee shall install, calibrate, maintain, and operate according to manufacturer's written instructions a flow meter measuring the exhaust flow from emission point TDB01.
- f. The permittee shall develop and keep on-site a quality assurance (QA) plan for all the continuous monitoring equipment described in this condition. For the CEMS and fuel flow meters, the permittee may, with Director's 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.
- g. Records of readings, calibrations, performance evaluations, quality assurance tests/checks, and maintenance performed shall be maintained in accordance with Condition 3.4.2.

[45CSR16; 40 CFR §60.7(f), §§60.4333(b) & (b)(1), §60.4345; 45CSR13: R13-2334, 4.2.8.]

4.2.12. To demonstrate compliance with the SO₂ emission standard of Condition 4.1.4.a.ii., the permittee shall sample and analyze the refinery fuel gas each operating day that refinery fuel gas is combusted by duct burner associated with TDB01.

- a. A representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see 40 CFR §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see 40 CFR §60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see 40 CFR §60.17).
- b. The fuel analysis required in this condition may be performed either by the permittee, or a service contractor retained by permittee. The collected samples shall be analyzed to determine the total sulfur content of the refinery fuel gas using: ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17).

If the permittee satisfies the criteria under 40 CFR §60.4370(c), the permittee may switch from the daily operating day sampling schedule, as required in this condition, to one of the two "custom schedules" as prescribed in 40 CFR §60.4370(c).

Records of the analyses, to include the date/time when the sample was taken and analyzed and chain of custody of the sample shall be maintained in accordance with Condition 3.4.2. of this permit.

Excess SO₂ emissions are for each operating hour that the duct burner is combusting refinery fuel gas in the period beginning on the date and hour of any sample for which the sulfur content of the refinery fuel gas exceeds the applicable limit in Condition 4.1.4.a.ii. and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

As an alternative to the above monitor requirements, the permittee may elect to utilize the daily average H₂S concentration readings of the refinery fuel gas from the H₂S monitor as required in Condition 4.2.6.e. and convert the daily average H₂S concentration into the form of the SO₂ emission standard stated in Condition 4.1.4.a.ii. The permittee shall determine excess SO₂ emissions as outlined in 40CFR§60.4385 for each reporting period (if any) and report such excess SO₂ emissions in accordance with 40CFR§60.4375(a) and Condition 3.5.3.

[45CSR16; 40 CFR §60.7(f), §60.4370(b), §60.4370(c), §60.4385(a), §60.13(i) and Approval Letter of Ergon-West Virginia Inc. Request for Regulatory Applicability Determination: Exemption from NSPS KKKK SO₂ Limits for Sources Subject to NSPS Ja, Dated April 21, 2025; 45CSR13: R13-2334, 4.2.9.]

- 4.2.13. For determining compliance with this emission limit in Condition 4.1.19., the permittee shall monitor cooling water flow rate continuously and the concentration of total dissolved solids contained in the make-up water of the fluid cooler or specific conductivity on a daily basis when the fluid cooler is operating. If the permittee uses a correlation curve or ratio between total dissolve solids concentration and specific conductivity, the Director or his/her representative may request the permittee verify the correlation at any reasonable time with just cause. The permittee shall determine the PM, PM₁₀, and PM_{2.5} emissions from the fluid cooler using a method that accurately predicts these specific pollutants from the fluid cooler. Such determination shall be conducted monthly. Records of such monitoring and determinations shall be maintained in accordance with Condition 3.4.2. of this permit.
[45CSR13: R13-2334, 4.2.10.]

4.3. Testing Requirements

Heaters H-101R, H-102R, H-500S, and H-501R

- 4.3.1. The permittee shall conduct biennial (once every 2 years) performance tests according to the requirements in 40 CFR §60.104a(i), establish a maximum excess O₂ operating limit or operating curve for Heater H-101R according to the requirements in §60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of 40 CFR §60.107a to demonstrate compliance. If an O₂ operating curve is used (i.e., if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of 40 CFR §60.107a, respectively.
- a. ~~i.~~—For heaters H-101R, H-102R, H-501R, and 505R: The permittee shall determine compliance with the NO_x emissions limits in 40 CFR §60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:
1. 40 CFR Part 60 Appendix A-1, Method 1 for sample and velocity traverses;
 2. 40 CFR Part 60 Appendix A-1, Method 2 for velocity and volumetric flow rate;
 3. 40 CFR Part 60 Appendix A-2, Method 3, 3A, or 3B for gas analysis. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-2, Method 3B;
 4. ~~5.~~40 CFR Part 60 Appendix A-4, Method 7, 7A, 7C, 7D, or 7E for moisture content and for the concentration of NO_x calculated as NO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by

reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-41, Method 7 or 7C.

5. [For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in 40 CFR §§60.107a\(c\)\(6\) or \(d\)\(8\), the owner or operator shall establish the O₂ operating limit or O₂ operating curve based on the performance test results according to the requirements in 40 CFR §§60.104a\(i\)\(6\)\(i\) or \(ii\), respectively.](#)

[i If a single O₂ operating limit will be used:](#)

- [A. Conduct the performance test following the methods provided in 40 CFR §§60.104a\(i\)\(1\), \(2\), \(3\) and \(5\) when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.](#)
- [B. Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit \(regardless of averaging time\), then the test is considered to be a valid test.](#)
- [C. Determine the average O₂ concentration for each test run of a valid test.](#)
- [D. Calculate the O₂ operating limit as the average O₂ concentration of the three test runs from a valid test.](#)

[ii If an O₂ operating curve will be used:](#)

- [A. Conduct a performance test following the methods provided in 40 CFR §§60.104a\(i\)\(1\), \(2\), \(3\) and \(5\) at a representative condition for each operating range for which different O₂ operating limits will be established. Different operating conditions may be defined as different firing rates \(e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity\) and/or, for co-fired process heaters, different fuel mixtures \(e.g., primarily gas fired, primarily oil fired, and equally co-fired, i.e., approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil\). Performance tests for different operating ranges may be conducted at different times.](#)
- [B. Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit \(regardless of averaging time\), then the test is considered to be a valid test.](#)
- [C. If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions \(i.e., when the process heater is firing at 50 percent or](#)

less of the rated heat capacity). If O₂ operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

- D. Determine the average O₂ concentration for each test run of a valid test.
 - E. Calculate the O₂ operating limit for each operating range as the average O₂ concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.
 - F. Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O₂ operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O₂ operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.
 - G. Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.
- 6. The owner or operator of a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O₂ limit, as provided in 40 CFR §§60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in §60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.
 - 7. The owner or operator shall use Equation 8 of 40 CFR §60.104a to adjust pollutant concentrations to 0-percent O₂ or 0- percent excess air.

[45CSR16, 40 CFR §§60.104a(i)(1) - (i)(3) and (i)(6) - (i)(8); §60.107a(c)(6); 45CSR13, R13-2334, 4.3.1.]

4.3.2. ~~j-~~For heaters H-101R, H-102R, H-501R, and 505R: The permittee shall determine compliance with the applicable H₂S emissions limit in 40 CFR §60.102a (g)(1) for a fuel gas combustion device according to the following test methods and procedures:

- ~~1.—40 CFR Part 60 Appendix A-1, Method 1 for sample and velocity traverses;~~
- ~~2.—40 CFR Part 60 Appendix A-1, Method 2 for velocity and volumetric flow rate;~~
- ~~3.—40 CFR Part 60 Appendix A-2, Method 3, 3A, or 3B for gas analysis. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-2, Method 3B;~~

- [a.](#) ~~4.~~ 40 CFR Part 60 Appendix A-5, Method 11, 15, or 15A or 40 CFR Part 60 Appendix A-6, Method 16 for determining the H₂S concentration for affected plants using an H₂S monitor as specified in 40 CFR §60.107a (a) (2). The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-5, Method 15A. The permittee may demonstrate compliance based on the mixture used in the fuel gas combustion device or for each individual fuel gas stream used in the fuel gas combustion device.
- [1.](#) ~~i.~~ For 40 CFR Part 60 Appendix A-5, Method 11, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H₂S may necessitate sampling for longer periods of time.
- [2.](#) ~~ii.~~ For 40 CFR Part 60 Appendix A-5, Method 15, at least three injects over a 1-hour period constitutes a run.
- [3.](#) ~~iii.~~ For 40 CFR Part 60 Appendix A-5, Method 15A, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-5, Method 15A.
- [4.](#) ~~iv.~~ If monitoring is conducted at a single point in a common source of fuel gas as allowed under 40 CFR §60.107a (a) (2) (iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

[\[45CSR16; 40 CFR §60.104a\(j\)\]](#)

~~[45CSR16, 40 CFR §60.104a(i) and (j), 45CSR13, R13-2334, 4.1.19, and 4.3.1.]~~

Boilers A and B, Heaters H-201, H-701, H-500S, H-600S

- [4.3.3.](#) ~~4.3.2.~~ [For Boilers A and B, Heaters H-201, H-701, H-500S, H-600S:](#) Any source for which compliance with sulfur dioxide emissions limitations are not demonstrated using continuous emission monitoring systems, must demonstrate compliance in accordance with Section [4.2.5](#), ~~4.2.7~~, not less frequently than semi-annually. At least three test runs, each with sufficient samples to characterize a two-hour period representative of normal source operation, shall be required for each compliance demonstration using the reference test procedures specified in Section [4.2.5](#), ~~4.2.7~~. The Director may order any person subject to CO-SIP-95-1 to conduct or have conducted an emissions test at any time that he or she has reason to believe that an emission limitation may be exceeded. The semi-annual tests shall otherwise be scheduled as ordered by or in consultation with the Director. No tests shall be required for units burning only natural gas.

[CO-SIP-95-1 - Condition V.9. (SIPed)]

Boilers A, B, and C, Heaters H-201, H-701, H-500S, H-600S, H-901

- [4.3.4.](#) ~~4.3.3.~~ [The permittee shall conduct an initial performance test within 60 days after achieving the maximum production rate at which the TDB01 will be operated, but not later than 180 days after the initial startup of TDB01 for demonstrating compliance with the NO_x standard in Condition 4.1.4.a.i. in accordance with the](#)

~~40 CFR §60.4400(a) and the requirements of Condition 3.3.1. During any period of failure or malfunction of the hydrogen sulfide continuous emission monitoring system required under Section 4.2.9., H₂S concentrations of the refinery fuel gas shall be determined by collection of not less than two (2) gas samples per eight (8) hour period which are analyzed by gas chromatography for hydrogen sulfide content, density and heating value in accordance with ASTM Method D 1945. The Company may request approval by the Director of alternative sampling and analytical methods for determination of these parameters during periods when the H₂S monitoring system has failed or malfunctioned.~~

a. There are two general methodologies that you may use to conduct the performance tests. For each test run:

1. Measure the NO_x concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of 40 CFR Part 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 of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_x emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_x)_c * Q_{std}}{P} \quad \text{(Equation 5 of 40 CFR 60, Subpart KKKK)}$$

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 § 60.4350(f)(2); or

2. Measure the NO_x and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. 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 this part to calculate the NO_x emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_x emission rate in lb/MWh.

b. 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.

c. Notwithstanding paragraph b. of this section (i.e., 40 CRR §60.4400(a)(2)), you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of 40 CFR Part 60 if the conditions in 40 CFR §60.4400(a)(3) are met:

- d. 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.
- e. NO_x emissions must be measured after the duct burner. The duct burner must be in operation during the performance test.
- f. Compliance with the applicable emission limit in Condition 4.1.4.a.i. 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.
- g. The permittee may elect to conduct the performance evaluation of the NO_x CEMS as part of the initial performance test (as described in 40 CFR §60.4405) for TDB01 or separately.
- h. The ambient temperature must be greater than 0 °F during the performance test.
- i. Records of such testing shall be maintained in accordance with Condition 3.4.2.

[45CSR16; 40 CFR §60.7(f), §60.8, §§60.4400(a), (b), (b)(2), (b)(4) –(b)(6); 45CSR13, R13-2334, 4.3.2. ~~GO-SIP 95-1—Condition V.11. (SIPed) (During fuel oil combustion only)~~

4.3.5. The permittee shall conduct an initial performance test within 60 days after achieving the maximum production rate at which the TDB01 will be operated, but not later than 180 days after initial startup of TDB01 and subsequent performance test on an annual basis (no more than 14 calendar months following the previous performance) for demonstrating compliance with the SO₂ standard in Condition 4.1.4.a.ii. for each type of gaseous fuel combusted by TDB01 using one of the compliance options in sub-paragraphs a. through d. of this condition. Any fuel combusted by this turbine and subject to the emission standards in 40 CFR §60.102a(g)(1)(ii) is exempt from the testing requirements in this condition.

- a. 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. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR part 75 may be used;
- b. Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see §60.17). The fuel analysis of this section may be performed either by the permittee or a service contractor retained by the permittee. Analyze the samples for the total sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17);
- c. Measure the SO₂ concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA

Methods 1 and 2 in appendix A of 40 CFR Part 60, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO₂ emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad (\text{Equation 6 of 40 CFR 60, Subpart KKKK})$$

Where:

E = SO₂ emission rate, in lb/MWh
 1.664×10^{-7} = conversion constant, in lb/dscf-ppm
(SO₂)_c = average SO₂ 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 §60.4350(f)(2); or

- d. Measure the SO₂ and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of 40 CFR Part 60. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). 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 Part 60 to calculate the SO₂ emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO₂ emission rate in lb/MWh.

These tests shall be conducted in accordance with Condition 3.3.1. of this permit. The report for each performance test shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR16; 40 CFR §60.7(f), §60.8, §60.4415 and Approval Letter of Ergon-West Virginia Inc. Request for Regulatory Applicability Determination: Exemption from NSPS KKKK SO₂ Limits for Sources Subject to NSPS Ja, Dated April 21, 2025; 45CSR13, R13-2334, 4.3.3.]

- 4.3.6. Within 12 months after initial startup with no less than 2 months of actual operation of the HRSG producing steam for the facility, the permittee shall conduct a performance test to demonstrate compliance with the mass CO, formaldehyde, and non-metal total HAPs limits in Condition 4.1.4.b. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method 320 of Appendix A of 40 CFR Part 63, or ASTM D6348-12e1 provided that the test plan preparation and implementation provisions of Annexes A1 through A8 of ASTM D6348-12e1 are followed and the %R as determined in Annex A5 of ASTM D6348-12e1 is equal or greater than 70% and less than or equal to 130%. The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Results} = ((\text{Measured Concentration in Stack})/(\%R)) \times 100$$

Such tests shall be conducted with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output and 90% of the steam capacity of the HRSG or within 90% of recorded hourly

steam output since initial startup. During the three test runs, the duct burner shall be firing during all periods of the testing at a rate that is represented of future operation of the duct burner.

Other HAPs to be measured as Total HAPs are:

<u>Acetaldehyde</u>	<u>Ethylbenzene</u>	<u>n-Xylene</u>
<u>Acrolein</u>	<u>n-Hexane</u>	<u>p-Xylene</u>
<u>Benzene</u>	<u>Naphthalene</u>	<u>o-Xylene</u>
<u>Phenol</u>	<u>Propylene Oxide</u>	
<u>1,3-butadiene</u>	<u>Toluene</u>	

This test shall consist of three (3) 120 minutes test runs. Records of the testing results; and process data, fuel/heat input, parameters used to determine the status of the SoLoNO_xTM mode of the combustion turbine record during the testing each event shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR13, R13-2334, 4.3.4.]

4.3.7. The permittee shall conduct subsequent testing for CO, formaldehyde, and total HAPs limits to demonstrate compliance of the limits in Condition 4.1.4.b. within 180 days when the average utilization of the duct burner is greater than 352,826 MMBtu per year on gross heat input basis over the previous 24 months from the most recent compliance demonstration. Said subsequent test shall be conducted as outlined in Condition 4.3.6. of this permit.

As an alternative to conducting subsequent testing as required in the above paragraph, the permittee shall conduct tune-ups of the duct burner for TBD01 26 months from the initial compliance test as required in Condition 4.3.6 and once every 26 months thereafter. Such tune-ups shall be conducted in accordance with the manufacturer's instructions. If no manufacturer's instructions exist, the permittee shall develop a written tune-up procedure which shall include the following as a minimum:

- a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment.
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (permittee may delay the inspection until the next scheduled unit shutdown)
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, the optimization for NO_x emissions needs to consistent with the manufacturer's NO_x concentration setting point unless otherwise stated in this permit.
- e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. The permittee may need to measure the concentration of CO and O₂ upstream of the duct burner to optimize the emissions of CO from the actual duct burner

Records of these tune-ups shall include the following and maintained accordance with Condition 3.4.2.:

The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the duct burner. If concentrations of NO_x were taken during the tune-up of the unit, record of such measurements shall be included; and

A description of any corrective actions taken as a part of the tune-up.

Should the permittee elect to implement the tune-up work practice as an alternative to the subsequent testing, the permittee shall notify the Director in accordance with Condition 3.5.3. within 12 months following the initial compliance demonstration as required in Condition 4.3.6.

[45CSR13, R13-2334, 4.3.5.]

4.4. Recordkeeping Requirements

~~All Boilers except the Portable Boiler and Heaters~~

- 4.4.1. To determine compliance with the emission limits set forth set forth in Conditions 4.1.1., and 4.1.3., the permittee shall keep monthly records of the operating schedule, amount of fuel by type (e.g., refinery gas plus natural gas, natural gas) consumed within the boilers, individually. By no later than the 15th day of the following month, the permittee shall determine the monthly emissions and 12-month rolling total from each respective boiler. Mass NO_x emissions from each boiler shall be based on valid CEM data from the respective unit. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. Compliance with these streamlined requirements will ensure compliance with CO-SIP-95-1 – Condition IV.3.A. ~~To determine compliance with restrictions set forth in Section 4.1.6., the permittee shall document the frequency, length of time, amount of fuel oil consumed, and estimate of emissions during DOT maintenance and periods of natural gas curtailment in which fuel oil was combusted. To determine compliance with fuel oil sulfur content limits set forth in Section 4.1.6., the permittee shall keep records of the sulfur content of all fuel oil received for the purpose of combustion. Each batch of fuel oil shall have its sulfur content determined by test method ASTM D4294. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement E, Chapter 1.3 may be used to estimate emissions.~~

[45CSR§8.3.3.; 45CSR13: R13-2334, 4.4.5. ~~4.4.4.~~ CO-SIP-95-1 - Condition IV.3.A. (SIPed)]

~~All Boilers and Heaters Except H-201~~

- 4.4.2. To comply with the emission limits set forth set forth in Conditions 4.1.5., 4.1.6., 4.1.7., 4.1.8., 4.1.9. 4.1.10., 4.1.11., 4.1.12., 4.1.13., and 4.1.14., the permittee shall determine the monthly emissions and 12-month rolling total emissions from each respective heater by no later than the 15th day of the following month. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. ~~The operators of fuel burning units shall maintain a periodic exception report for each unit. Such reports shall include, but may not be limited to the date and time of start ups and shutdowns. All such requirements, including notification by telephone, telefax, or other such method determined by the Director, shall be deemed to be satisfied when the reports are maintained on site for a period of no less than five (5) years and shall be made available upon request to the Director or his/her duly authorized representative.~~

[~~45CSR§2-8.3.b.;~~ 45CSR13: Permit R13-2334, 4.4.6. ~~4.4.5.]~~

- 4.4.3. The permittee shall maintain records of the operating schedule and the quantity of fuel consumed [by type consumed](#) in each [boiler and process heater monthly, at a minimum](#). ~~fuel burning unit monthly, at a minimum, but may record it more often at the discretion of the permittee.~~
[45CSR16; 40 CFR §60.48c(g)(3); 45CSR§2-8.3.3. ~~e.~~; 45CSR13: Permit R13-2334, [4.4.4](#), [4.4.6](#).]

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701

- 4.4.4. The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) subject to 45CSR§§10-3, 4 or 5 shall maintain on-site a record of all required monitoring data as established in a monitoring plan (see Appendix A) pursuant to 45CSR§10-8.2.3. ~~e.~~ Such records shall be made available to the Director or his duly authorized representative upon request. Such records shall be retained on-site for a minimum of five years.
[45CSR§10-8.3.1. ~~a.~~; 45CSR13: Permit R13-2334, [4.4.7](#).]
- 4.4.5. [For Heaters H-201, H-500S, H-600S, and H-701, the permittee shall determine total daily sulfur dioxide emissions from each of these heaters attributable to each fuel fired during twenty-four \(24\) hours period that Sulfur dioxide emissions attributable to the combustion of refinery fuel gas shall be determined using continuous hydrogen sulfide monitoring data collected in accordance with Condition 4.2.7. in conjunction with daily determination of the RFG heating value and density and accurate daily measurements of the volume of RFG fired in each heater. Said records shall be maintained in accordance with Condition 3.4.2. of this permit.](#) ~~The owner or operator of a fuel burning unit(s) or a combustion source(s) shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each unit in a manner specified 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§10-8.3.e.~~; 45CSR13: Permit R13-2334, [4.4.7](#), ~~8.~~ [CO-SIP-95-1 - Conditions V.4.A, and V.4.C. \(SIPed\)](#)]

Boilers A and B, All Heaters (except H-101R, H-102R, H-500S, H-501R, H-441 and H-1101)

- 4.4.6. For any periods for which sulfur dioxide or oxides emissions data are not available [for demonstrating compliance with Condition 4.1.15., 4.1.16. and 4.1.5.b. of this permit](#), the ~~permittee owner or operator of the affected facility~~ shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
[40 CFR §60.107(d); ~~and~~ 45CSR§16-4.1; 45CSR13: Permit R13-2334, [4.4.8](#), ~~14.~~]
- 4.4.7. The Company shall maintain records of the occurrence and duration of any start-up, shut-down or malfunction in the operation of sources subject to CO-SIP-95-1 ([Boilers A and B, All Heaters \(except H-101R, H-102R, H-500S, H-501R, H-441 and H-1101\)](#)), any malfunction of air pollution control equipment or any periods during which a continuous monitoring system or device is inoperative.
[CO-SIP-95-1 - Condition VI.4. (SIPed)]

Boilers A and B

- 4.4.8. [The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring devices, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance](#)

performed on these systems or devices; and all other information required by 40 CFR60 recorded in a permanent form suitable for inspection. The file shall be retained in accordance with Condition 3.4.2. of this permit, except as follows:~~To determine compliance with the emission limits set forth for Boiler A and Boiler B set forth in Section 4.1.14, the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the two boilers, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4 may be used to estimate monthly emissions of all pollutants except SO₂. The SO₂ monthly emissions shall be estimated using a blended fuel emission factor of 0.00577 lb SO₂/MMBtu for 20% refinery gas and 80% natural gas. Compliance with the yearly limit shall be based on a 12 month rolling total in accordance with Section 2.1.4. Compliance with this limit shall demonstrate compliance with the less stringent requirement of CO SIP 95-1, Condition IV.3.A. (SIPed) and 45CSR§10-3.1.e.~~

~~[45CSR13: Permit R13-2334, 4.4.9., 45CSR§30-5.1.e., CO SIP 95-1 Condition IV.3.A. (SIPed) and 45CSR§10-3.1.e.]~~

- a. Where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard using a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under 1st paragraph of this condition, the permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.
- b. Where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under 1st paragraph of this condition, the permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Director and/or Administrator.

[45CSR16; 40 CFR §§60.7(f), (f)(1), (f)(2); 45CSR13: Permit R13-2334, 4.4.9.]

Boiler C

- 4.4.9. The following requirements shall be used in determining compliance with NSPS Subpart KKKK NO_x limits and identifying excess emissions from CEMs data.~~To determine compliance with the emission limits for Boiler C, set forth in Section 4.1.17., the permittee shall keep monthly records of the amount of natural gas consumed within Boiler C and the hours of operation. This information along with appropriate emission factors from EPA's Compilation of Air Pollutant Emission Factors AP-42 Fifth Edition, Volume I, Supplement D: Stationary Point and Area Sources (AP-42), Chapter 1.4. may be used to estimate monthly emissions of all pollutants except NO_x. The emission factor for NO_x shall be 0.050 lb/MMBtu. Compliance with the yearly limit shall be based on a 12 month rolling total in accordance with Section 2.1.4.~~

~~[45CSR13: Permit R13-2334, 4.4.10.]~~

- a. All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).
- b. 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 and lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR Part 60. For any hour in which the hourly average O₂ concentration

exceeds 19.0 percent O₂, a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.

- c. Correction of measured NO_x concentrations to 15 percent O₂ is not allowed for the NO_x NSPS Subpart KKKK limit listed in Condition 4.1.4.a.i.
- d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in Subpart D of 40 CFR Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c) and in Condition 4.5.1.
- e. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
- f. Calculate the hourly average NO_x emission rates, in units of the emission standards under 40 CFR §60.4320, using the following equation for units complying with the output-based standard:
 - 1. For Simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \quad \text{(Equation 1 of 40 CFR 60, Subpart KKKK)}$$

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/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

- 2. For combined-cycle operation: For complying with the NO_x output-based standard, the permittee shall use Equation 1 of 40 CFR 60, Subpart KKKK, except that the gross energy output (P) is calculated as the sum of the total electrical and thermal 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:

$$P = (Pe)_t + (Pe)_c + P_s + P_o \quad \text{(Equation 2 of 40 CFR 60 Subpart KKKK)}$$

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,

(Pe)_c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_s = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Equation 3 of 40 CFR 60 Subpart KKKK})$$

Where:

P_s = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW.

Q = measured steam flow rate in lb/h.

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413×10^6 = conversion from Btu/h to MW.

P_o = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

- g. “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. The permittee shall determine excess emissions for each 30-day rolling average NO_x emission rate is greater than the Subpart KKKK Standard in Condition 4.1.4.a.i. of this permit.
- h. 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, diluent gas (CO₂ or O₂) 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.
- i. A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

[45CSR16; 40 CFR §60.4350, §§60.4380(b)(1), (b)(2), (c)(2); 45CSR13: Permit R13-2334, 4.4.14.]

- 4.4.10. To demonstrate compliance with the annual emission limits set forth set forth in Conditions 4.1.4.b. and 4.1.4.f., the permittee shall determine the monthly emissions and 12-month rolling total emissions from Emission Point TDB01 by no later than the 15th day of the following month. For periods that CEMs data is not valid, the permittee shall use the best information available and operational status of the combustion turbine (e.g., SoLoNO_x, non-SoLoNO_x mode, startup event, shutdown event) and duct burner to determine NO_x emissions for the period. For periods equal to and less than one operating hour of missing or invalid CEM data, the permittee is allowed to use the average of NO_x emissions of the hour before and hour after the missing hour if the operating status of the combustion turbine and duct burner was the same for all periods. Said records, which should include calculations in determining NO_x for periods of the missing or invalid CEM data, shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR13: Permit R13-2334, 4.4.15.]

~~(1) — Except as provided under 40 C.F.R. §§60.48c(g)(2) and (g)(3), the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.~~

~~(2) As an alternative to meeting the requirements of 40 C.F.R. §60.48c(g)(1), the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO₂ 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.~~

~~(3) As an alternative to meeting the requirements 40 C.F.R. §60.48c(g)(1), 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 this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO₂ 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.~~

~~**[40 C.F.R. §60.48c(g) and 45CSR§16-4.1]**~~

- 4.4.11. All records required under 40 C.F.R. 60 Subpart Dc shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
~~**[40 C.F.R. §60.48c(i) and 45CSR§16-4.1]**~~

~~**Heaters H-101R, H-102R, H-201, H-441, H-501R, H-701, H-500S and H-600S**~~

- 4.4.12. To demonstrate compliance with energy input limits set forth in Conditions 4.1.4.h. and 4.1.4.i., each month the permittee shall determine the hourly amount of energy input into the combustion turbine and duct burner on a daily average based for each operating day by no later than the 15th day of the following month. Said records shall be maintained in accordance with Condition 3.4.2. of this permit.
~~**[45CSR13: Permit R13-2334, 4.4.16.]**~~

~~To determine compliance with the emission limits set forth for H-101R, H-102R, and H-501R set forth in Section 4.1.18., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within both heaters for H-101R and H-102R, and individually for H-501R. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4. may be used to estimate monthly emissions of all pollutants except NO_x and SO₂. SO₂ emission factors shall be based on the 1995 SO₂ SIP and heating value (HHV) of 1019 Btu/scf, which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.4. (SIPed) and 45CSR§10-3.1.e.~~
~~**[45CSR13: Permit R13-2334, 4.4.11. (H-101R, H-102R, H-501R), CO-SIP-95-1—IV.4. (SIPed); 45CSR§10-3.1.e.]**~~

- 4.4.13. Each month the permittee shall identify all periods that the combustion turbine was not operating in the SoLoNO_xTM mode and reason for not operating the combustion turbine in the SoLoNO_xTM mode by no later than the 15th of the following month. The permittee shall maintain records either on-site or off-site and be accessible to the Director or his/her duly authorized representative within seven (7) calendar days of the request of records of the recorded parameters used to determine the status for the SoLoNO_xTM mode. Said records shall be maintained in accordance with Condition 3.4.2. of this permit except as stated in this condition.

[\[45CSR13: Permit R13-2334, 4.4.17.\]](#)

~~To determine compliance with the emission limits for H 441 set forth in Section 4.1.19., the permittee shall keep monthly records of the amount of natural gas consumed in the heater. This information along with appropriate emission factors from EPA's AP 42 Fifth Edition, Volume I, Supplement D, Chapter 1.4 may be used to estimate monthly emissions.~~

~~[45CSR13: Permit R13-2334, 4.4.12. (H 441)]~~

~~4.4.14. To determine compliance with the emission limits set forth for H 201, H 500 Series, H 600 Series, and H 701 in Sections 4.1.19. and 4.1.22., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the four heaters, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4. may be used to estimate monthly emissions of all pollutants except SO₂. SO₂ emission factors shall be based on the 1995 SIP and heating value (HHV), which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12 month rolling total in accordance with Section 2.1.4. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent requirement of CO SIP 95 1, Condition IV.5. and 7. (SIPed) and 45CSR§10-3.1.e.~~

~~[45CSR13: Permit R13-2334, 4.4.13. (H 201, H 500S, H 600S, H 701), CO SIP 95 1—IV.5. and 7. (SIPed); 45CSR§10-3.1.e.]~~

Heater H-901

~~4.4.15. The permittee shall keep monthly records of the amount of refinery fuel gas consumed by H 901. To determine compliance with NO_x, SO₂, VOC, and CO emissions limits for H 901, emission factors from manufacturer's specifications along with fuel gas consumption may be used. To determine compliance with the PM emission limits, AP 42 emission factors Table 1.4. 2 (1998) along with fuel gas consumption data may be used. Said records shall be maintained on site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.15.]~~

~~4.4.16. The permittee shall maintain continuous record for the H₂S concentration in the refinery fuel gas consumed by H 901. Said records shall be maintained on site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.16.]~~

Heater H 1101

~~4.4.17. The permittee shall keep monthly records of the amount of natural gas consumed by H 1101. To determine compliance with the NO_x, SO₂, and CO emission limits for H 1101, the permittee may use manufacturer's specifications and natural gas consumption. To determine compliance with the VOC and PM emission limit, natural gas consumption data and AP 42 Table 1.4 2 (1998) using an average gas high heating value (HHV) of 1020 BTU/scf may be used. Said records shall be maintained on site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.17.]~~

Heaters H 101R, H 102R, H 500S, and H 501R

~~4.4.14.~~ ~~4.4.18.~~ The permittee shall maintain records in accordance with 40 CFR §60.108a:

- a. Each permittee subject to the emissions limitations in 40 CFR §60.102a shall comply with the notification and recordkeeping requirements in 40 CFR §60.7 and other requirements as specified in 40 CFR §60.108a [which shall include Condition 4.5.2. of this permit](#)
- c. The permittee shall maintain the following records:
 6. Records of discharges greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device [subject to Condition 4.1.15 of this permit](#). The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:
 - i. A description of the discharge.
 - ii. The date and time the discharge was first identified and the duration of the discharge.
 - iii. The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices.
 - v. For each discharge greater than 500 lb SO₂ in excess of the applicable short-term emissions limit in 40 CFR §60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H₂S in the fuel gas or the measured concentration of SO₂ in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices.
 - vii. For each discharge greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device, the cumulative quantity of H₂S and SO₂ released into the atmosphere. For fuel gas combustion devices, assume 99-percent conversion of H₂S to SO₂.
 - viii. The steps that the owner or operator took to limit the emissions during the discharge.
 - ix. The root cause analysis and corrective action analysis conducted as required in 40 CFR §60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under 40 CFR §60.103a(e).
 - x. For any corrective action analysis for which corrective actions are required in 40 CFR §60.103a(e), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

[Said records shall be maintained in accordance with Condition 3.4.2. of this permit.](#)
[45CSR16, 40 CFR §§60.108a(a) and (c) (6), 45CSR13: R13-2334, ~~4.4.10. 18.~~ and ~~4.4.11. 4.5.5.~~]

Portable Boiler

[4.4.15.](#) ~~4.4.19.~~ In order to demonstrate compliance with the requirements of 4.1.[23](#) ~~34~~ and 4.2.[10](#) ~~15~~, the permittee shall record the number of hours of operation of the Portable Boiler on a monthly basis.
[45CSR13: R13-2334, [4.4.12.](#) ~~19~~]

[4.4.16.](#) ~~4.4.20.~~ In order to demonstrate compliance with the requirements of 4.1.[24](#), ~~32~~, the permittee shall record all the dates on which the Portable Boiler is brought on site and removed from the site.
[45CSR13: R13-2334, [4.4.13.](#) ~~20~~]

4.5. Reporting Requirements

~~All Boilers, Heaters H 101R, H 102R, H 441, H 501R, H 701, H 500S, H 600S, H 901, H 1101~~

4.5.1. The [permittee](#) ~~owner or operator of a fuel burning unit(s) subject to 45CSR2~~ shall report to the Director any malfunction of [Boilers A, B, C, and the duct burner when in operation for the combustion turbine](#) ~~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 Director:
 1. The excess opacity period does not exceed thirty (30) minutes within any 24-hour period; and
 2. Excess opacity does not exceed 40%.
- b. The [permittee](#) ~~owner or operator~~ shall report to the Director any malfunction resulting in excess particulate matter or excess opacity, not meeting the criteria set forth in 45CSR§2-9.3.[1](#) ~~a~~, by telephone, ~~telefax~~, or e-mail by the end of the next business day after becoming aware of such condition. The [permittee](#) ~~owner or operator~~ shall file a certified written report concerning the malfunction with the Director within thirty (30) days [in accordance with Condition 3.5.3.](#) 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 program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.; 45CSR13: R13-2334, 4.5.1.]

~~Boilers A and B, Heaters H 101R, H 102R, H 501R, H 500S, H 600S, H 901~~

- 4.5.2. For the boilers, process heaters, and duct burner subject to the H₂S standard in Conditions 4.1.15., 4.1.16., and 4.1.17.; Boilers A and B to the NO_x standard in Condition 4.1.1.b.; and the Heater H-101R to the NO₂ standard in Condition 4.1.5.b., the permittee shall submit excess emissions and monitoring system performance report to the Director in accordance with Condition 3.5.3. for the six (6) month period of January 1 through June 30 and July 1 through December 31 by no later than 30th day following the end of each six (6) month period. ~~The owner or operator shall submit a periodic exception report to the Director, in a manner specified by the Director. Such an exception report shall provide details of all excursions outside the range of measured emissions or monitored parameters established in an approved monitoring plan (see Appendix A) and shall include, but not be limited to, the time of the excursion, the magnitude of the excursion, the duration of the excursion, the cause of the excursion and the corrective action taken.~~

Such reports shall contain the following information:

- a. The information and in the format listed in Appendix B of this permit for each pollutant monitored.
- b. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
- c. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
- d. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- e. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- f. For units subject to Condition 4.1.15 and excess emissions occurred as defined in Condition 4.2.6.e., the permittee shall provide the additional information.
 1. The date that the exceedance occurred.
 2. An explanation of the exceedance.
 3. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and
 4. A description of the action taken, if any.
 5. The information described in 40 CFR §60.108a(c)(6) for all discharges listed in 40 CFR §60.108a(c)(6)
 6. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.
- g. For units subject to Condition 4.1.16 and excess emissions occurred as defined in Condition 4.2.6.f., the permittee shall identify those excess emissions in the report.

- h. For units subject to Condition 4.1.17 and excess emissions occurred as defined in Condition 4.2.6.g., the permittee shall identify those periods, which includes the duration of the excess emission, the magnitude of the excess emission in the report, and actions taken to resolve and/or minimize the magnitude of the excess emissions.
- i. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
- j. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Director or Administrator.
- k. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.

[45CSR§10-8.3.2, ~~b.~~; [45CSR16](#); [40 CFR §§60.7\(c\) and \(d\)](#), [§60.107\(f\)](#), [§60.108a\(d\)](#); 45CSR13: Permit R13-2334, 4.5.2.]

Boilers A and B, Heaters H-201, H-441, H-701, H-500S, H-600S

- 4.5.3. **For Boilers A and B, H-201, H-441, H-701, H-500S, H-600S:** The Company shall submit an excess emissions and monitoring systems performance report to the Director for all sources for which the Company is required to maintain and operate a continuous monitoring system or monitoring device for sulfur dioxide or hydrogen sulfide on a calendar monthly basis. All such reports shall be submitted by the 30th day following the end of each calendar month and shall contain the results of all determinations showing excess emissions regardless of whether the determinations are made by continuous monitoring data or by other methods established by CO-SIP-95-1. Written reports of excess emissions shall include the following information:
- a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, the date and time at which the excess emissions started and ended for each occurrence of excess emissions and the process operating time during the reporting period.
 - b. Specific identification of each period of excess emissions that occurred during start-ups, shut-downs and malfunctions of the affected facility. Each malfunction report filed with the Director in accordance with Section 4.5.4. shall be referenced by report number with the date of occurrence and date of report submission noted.
 - c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

- d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired or adjusted, such information shall be stated in the report.

If the total duration of excess emissions during the reporting period is less than one percent (1%) of the total operating time for the reporting period, and downtime for the continuous monitoring system for the reporting period is less than five percent (5%) of the total operating time for the reporting period, only the summary report form listed as Figure 1 in 40 CFR Part 60.7(d) shall be submitted, and the excess emission report described above need not be submitted unless requested by the Director. If the total duration of excess emissions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period, or the total continuous system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the summary report form and the excess emission report described above shall both be submitted to the Director.

[CO-SIP-95-1 - Condition VI.3. (SIPed)]

- 4.5.4. **For Boilers A and B, H-201, H-441, H-701, H-500S, H-600S:** The Company shall report to the Director, by telephone or telefax, any malfunction of such source or its air pollution control equipment which results in any excess sulfur dioxide emission rate or concentration within twenty-four (24) hours of becoming aware of such condition. The Company shall file a written report concerning the malfunction with the Director within ten (10) days, providing the following information:

- a. A detailed explanation of the factors involved or causes of the malfunction.
- b. The date and time of duration (with starting and ending times) of the period of excess emissions.
- c. An estimate of the mass of excess emissions discharged during the malfunction period.
- d. The maximum emission rate or concentration measured or otherwise determined during the malfunction in units of the applicable emissions standard.
- e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction.
- f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[CO-SIP-95-1 - Condition VI.7. (SIPed)]

Boiler C

~~4.5.5. The permittee is responsible for submitting notification of the date of construction or reconstruction, anticipated startup, and actual startup and complying with 40 CFR §60.40c, 40 CFR §60.48c, and 40 CFR §60.8. The permittee has complied with this requirement by submitting notification. Renotification will be required if modifications are made.~~

~~[40 CFR §60.48c and 45CSR§16-4.1.; 45CSR13: R13-2334, 4.5.3.]~~

- ~~4.5.6~~ 4.5.5. The reporting period for the reports required under this subpart is each six-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.

[40 C.F.R. §60.48c(j) and 45CSR§16-4.1]

Heater H 901

~~4.5.7. For any periods for which sulfur dioxide or oxides emissions data are not available for H 901, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
[40 CFR §60.107(d) and 45CSR§16-4.1; 45CSR13: Permit R13-2334, 4.5.4.]~~

Heaters H 101R, H 102R, H 500S, and H 501R

~~4.5.8. Each permittee subject to the emissions limitations in 40 CFR § 60.102a shall comply with the reporting requirements in 40 CFR § 60.7 and other requirements as specified in 40 CFR § 60.108a.
[45CSR16, 40 CFR §§ 60.108a (a), 45CSR13: R13-2334, 4.5.5.]~~

~~4.5.9. Each permittee subject to 40 CFR Part 60 Subpart Ja shall submit an excess emissions report for all periods of excess emissions according to the requirements of 40 CFR §60.7(c) except that the report shall contain the information specified in 40 CFR §60.108a(d)(1) through (7).~~

- ~~1. The date that the exceedance occurred;~~
- ~~2. An explanation of the exceedance;~~
- ~~3. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and~~
- ~~4. A description of the action taken, if any.~~
- ~~5. The information described in 40 CFR § 60.108a (c) (6) for all discharges listed in paragraph (c) (6).~~
- ~~6. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.~~
- ~~7. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.~~

~~[45CSR16, 40 CFR § 60.108a (d), 45CSR13, R13-2334, 4.5.5.]~~

4.5.6. The permittee shall prepare and submit an excess emission report on a semi-annual basis to the Director and Administrator for NO_x and SO₂ emissions from TBD01 as required by Subpart KKKK of 40 CFR 60. The initial compliance period is from initial startup of combustion turbine (TDB01) to either December 31 or June 30 whichever date comes first. Subsequent reporting periods shall be every six months thereafter (e.g., January 1 to June 30, July 1 to December 31). Reports must be submitted no later than the 30th day following the end of the reporting period. Each report must contain the following information that occurred within the respective reporting period. Each report shall be submitted in accordance with Condition 3.5.3.

- a. Excess Emissions of sulfur dioxide emissions shall mean the total sulfur content of the fuel being combusted ~~in the turbine~~ exceeds the limit specified in 40 CFR §60.4330 (See Condition 4.1.4.a.ii. SO₂ limit for Subpart KKKK). ~~An SO₂ excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. If electing to utilize the alternative monitor requirements for daily average H₂S concentration readings of the refinery fuel gas from the H₂S monitor as required in Condition 4.2.6.e., the daily average concentration (converted from H₂S into the form of the SO₂ emission standard stated in Condition 4.1.4.a.ii) shall be used to determine excess SO₂ emissions. An SO₂ excess emission occurs each unit operating hour included in any daily average concentration which exceeds the applicable limit and ending on the date and hour that a subsequent daily average demonstrates compliance with the SO₂ emission standard.~~
- b. Excess Emissions of NO_x means a specified averaging period ~~(30-day rolling)~~ over which the NO_x emissions are higher than the applicable emission limit in 40 CFR §60.4320 (See Condition 4.1.4.a.i. NO_x limit for Subpart KKKK).
- c. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you 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 start-up, shutdown, and malfunction.
- d. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each period of excess emissions. The process operating time during the reporting period.
- e. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted.
- f. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- g. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- h. The summary report form shall contain the information and be in the format shown in Appendix B of the permit unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
- i. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted, and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Administrator.
- j. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent

or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.

[45CSR16; 40 CFR §§60.7(c) and (d), §60.4375(a), §60.4380(b), §60.4385, §60.4395, 45CSR13: Permit R13-2334, 4.5.3.]

4.5.7. The permittee shall submit to the Director within 60 days of completion of CEMS performance evaluation for TDB01 two copies of the performance evaluation report to satisfy Part 60 notification requirements for certifying the CEMS.

[45CSR16; 40 CFR §§60.13(c) and (c)(2); 45CSR13: Permit R13-2334, 4.5.4.]

4.5.8. The permittee shall notify the Director within thirty (30) calendar days of switching to a different sampling schedule as allowed or required in Condition 4.2.1. of this permit. Such notification shall include the date of the actual switch and reason to include justification for switching the sampling schedule.

[45CSR13: Permit R13-2334, 4.5.5.]

4.5.9. The permittee shall submit a notification of the actual date of initial startup of TDB01 within 15 days after such date, to the Director and Administrator, in accordance with Condition 3.5.3. of this permit.

[45CSR16; 40 CFR §60.7(a)(3); 45CSR13: Permit R13-2334, 4.5.6.]

4.5.10. The permittee shall submit a notification acknowledging the provisions of Condition 4.1.3. (See 4.1.20. through 4.1.25. of this permit) of permit R13-2334 are no longer effective within 15 calendar days of the end date for Condition 4.1.25. of this permit (180 days after the actual initial startup date of TDB01) to the Director in accordance with Condition 3.5.3. of this permit.

[45CSR13: Permit R13-2334, 4.5.7.]

4.5.11. The permittee shall submit a notification for any exceedance of the annual emission limits in Condition 4.1.4. of this permit to the Director in accordance with Condition 3.5.3.

[45CSR13: Permit R13-2334, 4.5.8.]

4.6. Compliance Plan

4.6.1. None.

5.0 F1, T Load, OXIDIZER, MLD, MLDOX, and NH3OX Requirements

5.1. Limitations and Standards

5.1.1. The Main Flare [F1/00A-01], the Sour Gas Flare [F2/00A-03], the Truck Loading Thermal Oxidizer [OXIDIZER/00A-02], the Marine Loading Thermal Oxidizer [MLDOX/00A-04], and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX], are subject to the requirements of 45CSR6 including but 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 the use of the following formula:

$$\text{Emissions(lb/hr)} = F \times \text{Incinerator Capacity (tons/hr)}$$

where the factor, F, is as indicated in the table below:

Incinerator Capacity	F Factor
Less than 15,000 lbs/hr	5.43
15,000 lbs/hr or greater	2.72

Emission ID	Calculation	Limit (lbs/hr)
F1 [00A-01] and F2 [00A-03]	2.72 x 395,000 lbs/hr x 1 ton/2000 lbs	537.2
OXIDIZER [00A-02]	5.43 x 64.8 lbs/hr x 1 ton/2000 lbs	0.176
MLDOX [00A-04]	5.43 x 4600 lbs/hr x 1ton/2000 lbs	12.5
NH3OX [00A-05]	5.43 x 416.08 lbs/hr x 1 ton/2000 lbs	1.13

- 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.
- c. Incinerators, including all associated equipment and grounds, shall be designed, operated and maintained so as to prevent the emission of objectionable odors.

[45CSR§§6-4.1., 4.3, 4.6.; 45CSR13: Permit R13-2334, 5.1.6.]

5.1.2. No person shall cause, suffer, allow, or permit the emission into open air from any source operation an in-stack sulfur dioxide concentration exceeding 2000 ppm by volume from existing source operations. Note: “In-stack” concentration as interpreted for a flare means the exhaust concentration after combustion.

[45CSR§10-4.1.; 45CSR13: Permit R13-2334 - 5.1.7.]

- 5.1.3. a. For the Main Flare F1, the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H₂S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. 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 limit.

[40 CFR §60.103a(h), 45CSR§16-4.1; 45CSR13: Permit R13-2334, 5.1.9., and CO-SIP-95-1 - Condition IV.9. (SIPed) (00A-01)]

- b. For the Sour Gas Flare [F2], the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf) determined hourly on a 3-hour

rolling average basis. 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 paragraph. **[40 CFR §60.104(a)(1), 45CSR§16-4.1; 45CSR13: Permit R13-2334, 5.1.10., and CO-SIP-95-1 - Condition IV.9. (SIPed) (00A-03)]**

Compliance with these limits shall demonstrate compliance with the 50 gr/100dscf limit from CO-SIP-95-1, Condition IV.9.

- 5.1.4. During Truck Loading of gasoline, VOC emissions shall be controlled by the Loading Rack Thermal Oxidizer.
[45CSR13: Permit R13-2334, 5.1.3. (00A-02)]
- 5.1.5. Gas generated at the sour water stripper shall continue to be processed through the fuel gas treatment system and the Company shall exercise good operating and maintenance practices to maximize the utilization of the fuel gas treatment system to remove sulfur compounds from the sour gas stream and further provided, that in no event shall the emissions of sulfur dioxide from the sour gas flare exceed 18 lbs./hr.
[CO-SIP-95-1 - Condition IV.9. (SIPed)]
- 5.1.6. The permittee shall implement a program to investigate the cause of Acid Gas Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Acid Gas Flaring Incidents, and minimize Acid Gas Flaring Incidents. The permittee shall evaluate whether Acid Gas Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forth the Root Cause and all contributing causes of the Acid Gas Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Acid Gas Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.
- a. “Acid Gas Flaring Incident” means the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five hundred (500) pounds of more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the AG Flaring Incident. “Acid Gas” means any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of amine solution.
 - b. “Acid Gas Flaring” means the combustion of Acid Gas and/or Sour Water Stripper Gas in an Acid Gas Flaring Device. “Acid Gas Flaring Device” shall mean any device at EWVI that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The Acid Gas Flaring Device currently in service at EWVI is F2 [00A-03].
 - c. “Sour Water Stripper Gas” shall mean the gas produced by the process of stripping refinery sour water.
 - d. “Root Cause” means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.

- e. “Malfunction” means, as specified in 40 CFR Part §60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR13: Permit R13-2334, 5.1.16.]

- 5.1.7. In response to any Acid Gas or Hydrocarbon Flaring Incident from the Sour Gas Flare [F2], the permittee shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that Acid Gas or Hydrocarbon Flaring Incident.

[45CSR13: Permit R13-2334, 5.1.17.]

- 5.1.8. The permittee shall implement a program to investigate the cause of Hydrocarbon Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Hydrocarbon Flaring Incidents, and minimize Hydrocarbon Flaring Incidents. The permittee shall evaluate whether Hydrocarbon Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forth the Root Cause and all contributing causes of the Hydrocarbon Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Hydrocarbon Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.

- a. "Hydrocarbon Flaring Incident" means the continuous or intermittent Hydrocarbon Flaring, except for Acid Gas and/or Sour Water Stripper Gas, at a Hydrocarbon Flaring Device that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five-hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one Hydrocarbon Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the Hydrocarbon Flaring Incident.
- b. "Hydrocarbon Flaring" means the combustion of refinery-generated gases, except for Acid Gas and/or Sour Water Stripper Gas in a Hydrocarbon Flaring Device.
- c. "Hydrocarbon Flaring Device" means a flare device used to control (through combustion) any excess volume of a refinery generated gas other than Acid Gas and/or Sour Water Stripper Gas.
- d. “Root Cause” means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.
- e. “Malfunction” means, as specified in 40 CFR Part 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR13: Permit R13-2334, 5.1.18]

5.1.9. Emissions shall not exceed those listed below. Annual emission limits are based on a 12-month rolling basis.

Pollutant	Emission Point ID									
	F1 (pilot light)		F2 (pilot light)		TLOAD & OXIDIZER		MLD & MLDOX		NH3OX	
	TPM*	TPY	TPM*	TPY	TPM*	TPY	TPM*	TPY	TPM*	TPY
CO	0.007	0.074	0.013	0.129	0.21	2.12	0.27	2.67	0.80	7.96
NO _x	0.009	0.088	0.015	0.153	0.04	0.39	0.05	0.49	0.05	0.50
PM _{2.5}	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
PM ₁₀	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
PM	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
SO ₂					0.13	1.26	0.19	1.85	0.01	0.02
VOC	0.001	0.005	0.001	0.008	1.82	18.17	1.22	12.24	0.10	1.00
Total HAPs					0.32	3.22	0.13	1.3		
Benzene					0.03	0.32	0.01	0.08		

Pollutant	Emission Point ID			
	Railcar Unloading		Air Separator / Recovery Drum	
	TPM*	TPY	TPM*	TPY
VOC	1.46	17.55	0.36	4.35
Hexane	0.04	0.51	0.01	0.08
Benzene	0.04	0.49	0.01	0.08
Isooctane	0.01	0.04	0.01	0.01
Toluene	0.02	0.26	0.01	0.04
Ethylbenzene	0.01	0.04	0.01	0.01
Xylene	0.01	0.11	0.01	0.02
Total HAPs	0.12	1.45	0.02	0.23

*TPM = Tons per month

[45CSR13 - Permit R13-2334 - 5.1.1.]

5.1.10. The permittee shall not exceed the annual limits in the table below that correspond to the emission limits established in requirement 5.1.9. Annual quantities are based on a 12-month rolling basis.

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Marine Loading	Gasoline	62,031
	Light Crude Oil (including oil with a vapor pressure up to 11.0 psia)	306,600
	Diesel	37,065
	Kerosene	46,000
	Lube Oil/ Heavy Products	30,660
Truck Loading	Diesel	134,904
	Gasoline	134,904
	No. 6 Fuel Oil	13,650
	Kerosene	15,330
	Lube Oil/ Heavy Products	136,920

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Railcar Unloading	Waxy Crude	38,325
	Total Crude (Waxy & Penn)	76,650

[45CSR13 - Permit R13-2334 - 5.1.2.]

- 5.1.11. The Main Flare [F1] is an affected facility as that term is used in 40 CFR Part 60 and is subject to the requirements of 40 CFR Part 60, Subparts A and Ja . The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d) and with the applicable work practice standards of NSPS, Subpart Ja.

[45CSR16; 40 CFR §60.103a; 45CSR13: Permit R13-2334 - 5.1.13. and 5.1.15]

- 5.1.12. The Sour Gas Flare [F2] is an affected facility as that term is used in 40 CFR Part 60 and is subject to the requirements of 40 CFR Part 60, Subparts A and J. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d).

[45CSR13: Permit R13-2334, 5.1.14.]

- 5.1.13. Marine Loading.

- a. During marine loading of gasoline and light crude oil, VOC emissions shall be controlled by the Marine Barge Loading Thermal Oxidizer [MLDOX/ 00A-04]. MLDOX shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 98% for VOCs.

- b. All vessels loaded from the Marine Loading Dock (MLD) shall be submerged filled.

[45CSR13: Permit R13-2334, 5.1.4.]

- 5.1.14. Emissions from the Ammonia Destruction Unit (ADU) shall be routed to the ADU Thermal Oxidizer [NH3OX/00A-05] at all times that the ADU is in operation. The thermal oxidizer [NH3OX] shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 99.9% for VOCs.

[45CSR13: Permit R13-2334, 5.1.5.]

- 5.1.15. No refined products (e.g. gasoline, naphtha, ethanol, diesel) shall be received via rail.

[45CSR13: Permit R13-2334, 5.1.8.]

- 5.1.16. Existing sources with emissions less than 10 and 25 tons must meet the submerged fill standards of 46 CFR 153.282.

- a. The discharge point of a cargo tank filling line must be no higher above the bottom of the cargo tank or sump than 10 cm (approx. 4 in.) or the radius of the filling line, whichever is greater.

[46 C.F.R. §153.282]

[40 C.F.R. §63.560(a)(4); 45CSR34] (MLD and MLDOX)

- 5.1.17. Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.

[40 C.F.R. §60.502(a); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.18. The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in 40 C.F.R. §60.502(c).

[40 C.F.R. §60.502(b); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.19. Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:

- a. The owner or operator shall obtain the vapor tightness documentation described in 40 C.F.R. §60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.
- b. The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.
- c.
 - i. The owner or operator shall cross-check each tank identification number obtained in 40 C.F.R. §60.502(e)(2) with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded, unless either of the following conditions is maintained:
 - A. If less than an average of one gasoline tank truck per month over the last 26 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed each quarter; or
 - B. If less than an average of one gasoline tank truck per month over the last 52 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed semiannually.
 - ii. If either the quarterly or semiannual cross-check provided in 40 C.F.R. §60.502(e)(3)(i)(A) through (B) reveals that these conditions were not maintained, the source must return to biweekly monitoring until such time as these conditions are again met.
- d. The terminal owner or operator shall notify the owner or operator of each non-vapor-tight gasoline tank truck loaded at the affected facility within 1 week of the documentation cross-check in 40 C.F.R. §60.502(e)(3).
- e. The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.
- f. Alternate procedures to those described in 40 C.F.R. §60.502(e)(1) through (5) for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.

[40 C.F.R. §60.502(e); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.20. The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

[40 C.F.R. §60.502(f); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.21. The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

[40 C.F.R. §60.502(g); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.22. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in §60.503(d).

[40 C.F.R. §60.502(h); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.23. Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

[40 C.F.R. §60.502(j); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.24. Each owner or operator of an affected source under this subpart must comply with the requirements of 40 C.F.R §§63.11085(a) and (b).

(a) You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. 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.

(b) You must keep applicable records and submit reports as specified in 40 C.F.R. §63.11094(g) and 40 C.F.R. §63.11095(d).

[40 C.F.R. §63.11085; 45CSR34] (T Load) (During gasoline loading only)

- 5.1.25. The permittee must meet each emission limit and management practice in Table 2 to 40 C.F.R 63 Subpart BBBBBB that applies to you.

If you own or operate ...	Then you must ...
1. A bulk gasoline terminal loading rack(s) with a gasoline throughput (total of all racks) of 250,000 gallons per day, or greater. Gallons per day is calculated by summing the current day's throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365	(a) Equip your loading rack(s) with a vapor collection system designed to collect the TOC vapors displaced from cargo tanks during product loading; and
	(b) Reduce emissions of TOC to less than or equal to 80 mg/l of gasoline loaded into gasoline cargo tanks at the loading rack; and
	(c) Design and operate the vapor collection system to prevent any TOC vapors collected at one loading rack or lane from passing through another loading rack or lane to the atmosphere; and
	(d) Limit the loading of gasoline into gasoline cargo tanks that are vapor tight using the procedures specified in §60.502(e) through (j) of this chapter. For the purposes of this section, the term "tank truck" as used in

	§60.502(e) through (j) of this chapter means “cargo tank” as defined in §63.11100.

[40 C.F.R. §63.11088(a); Table 2 to 40 C.F.R 63 Subpart BBBBBB, 45CSR34] (T Load) (During gasoline loading only)

- 5.1.26. Requirements for equipment leak inspections at a bulk gasoline terminal, bulk plant, pipeline breakout station, or pipeline pumping station.
- (a) Each owner or operator of a bulk gasoline terminal, bulk plant, pipeline breakout station, or pipeline pumping station subject to the provisions of this subpart shall perform a monthly leak inspection of all equipment in gasoline service, as defined in 40 C.F.R. §63.11100. For this inspection, detection methods incorporating sight, sound, and smell are acceptable.
 - (b) A log book shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log book shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.
 - (c) Each detection of a liquid or vapor leak shall be recorded in the log book. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in 40 C.F.R. §63.11089(d) of this section.
 - (d) Delay of repair of leaking equipment will be allowed if the repair is not feasible within 15 days. The owner or operator shall provide in the semiannual report specified in 40 C.F.R. §63.11095(b), the reason(s) why the repair was not feasible and the date each repair was completed.
 - (e) You must comply with the requirements of this subpart by the applicable dates specified in 40 C.F.R. §63.11083.
 - (f) You must submit the applicable notifications as required under 40 C.F.R. §63.11093.
 - (g) You must keep records and submit reports as specified in 40 C.F.R. §§63.11094 and 63.11095.

[40 C.F.R. §63.11089; 45CSR34] (T Load) (During gasoline loading only)

5.2. Monitoring Requirements

- 5.2.1. The permittee shall monitor the PM emissions by conducting visible emissions checks in accordance with Section 4.2.1. of this permit.
[45CSR13 - R13-2334 - 5.2.1.]
- 5.2.2. To determine compliance with the emission rate limits set forth in Section 5.1.9., the permittee shall monitor hours of operation for pilot and non-pilot conditions of the Main Flare [F1] and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX]. Compliance with yearly limits shall be based on a 12-month rolling basis.
[45CSR13 - Permit R13-2334 - 5.2.2.]
- 5.2.3. To determine compliance with the annual emission rate limits set forth in Section 5.1.9. for the OXIDIZER and MLDOX, the permittee may estimate emissions using the monthly loading records, along with the

appropriate emission factors for loading losses from AP-42, Chapter 5.2 (7/08). Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13 - Permit R13-2334 - 5.2.3.]

- 5.2.4. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.13 for MLDOX, OXIDIZER, and NH3OX.

[45CSR16, 40 CFR §60.13, 45CSR13: R13-2334, 5.2.4]

- 5.2.5. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.107a for F1:
The owner or operator of a flare that is subject to the H₂S concentration requirement in Section 5.1.3.a. shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

- i. The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H₂S.
- ii. The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.
- iii. The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H₂S monitor.
- iv. Flares 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 fuel gas combustion devices or flares.
- v. The owner or operator of a flare subject to 40 CFR 60.103(c) through (e) may use the instrument required in 40 CFR §60.107a(e)(1) to demonstrate compliance with the H₂S concentration requirement in 40 CFR §60.103a(h) if the owner or operator complies with the requirements of 40 CFR §§60.107a(e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in 40 CFR §60.107a(e)(1) is used to demonstrate compliance with the H₂S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in 40 CFR §60.103a(h).
- vi. The owner or operator of modified flare that meets all three criteria in paragraphs A. through C. below shall comply with the requirements of Section 5.2.5.i. through v. no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to 40 CFR §60.13(i) until the flare is in compliance with requirements of Section 5.2.5.i. through v.
 - A. The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under §60.100a.
 - B. The owner or operator had an approved alternative monitoring plan or plans pursuant to §60.13(i) for all fuel gases combusted in the flare.

- C. The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

[45CSR16, 40 CFR §60.107a(a)(2), 45CSR13: Permit R13-2334, 5.2.5.]

- 5.2.6. In order to determine compliance with the railcar unloading throughput of condition 5.1.10, the permittee shall monitor and record the amount and type of crude oil unloaded from railcars on a monthly basis.

[45CSR13: Permit R13-2334, 5.2.6.]

- 5.2.7. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) while gasoline vapors are displaced to the vapor processor systems, as specified in 40 C.F.R. §§63.11092(b)(1) through (5). For each facility conducting a performance test under paragraph 40 C.F.R. §63.11092(a)(1), and for each facility utilizing the provisions of 40 C.F.R. §63.11092(a)(2) or (a)(3), the CMS must be installed by January 10, 2011.

- (5) If you have chosen to comply with the performance testing alternatives provided under 40 C.F.R. §63.11092(a)(2) or (a)(3), the monitored operating parameter value may be determined according to the provisions in paragraph 40 C.F.R. §63.11092(b)(5)(i) or (b)(5)(ii).

(i) Monitor an operating parameter that has been approved by the Administrator and is specified in your facility's current enforceable operating permit. At the time that the Administrator requires a new performance test, you must determine the monitored operating parameter value according to the requirements specified in 40 C.F.R. §63.11092(b).

(ii) Determine an operating parameter value based on engineering assessment and the manufacturer's recommendation and submit the information specified in paragraph 40 C.F.R. §63.11092(b)(4) for approval by the Administrator. At the time that the Administrator requires a new performance test, you must determine the monitored operating parameter value according to the requirements specified in 40 C.F.R. §63.11092(b) of this section.

Note: In accordance with 40 CFR §63.11092(a)(2) and §63.11092(b)(5)(i), the OXIDIZER is equipped with a monitoring system to measure and record the temperature during gasoline truck loading events. The OXIDIZER temperature must achieve 1,000 °F during each loading event.

[40 C.F.R. §63.11092(b)(5);45CSR34] (T Load and OXIDIZER)

- 5.2.8. Each owner or operator of a bulk gasoline terminal subject to the provisions of 40 C.F.R. 63 Subpart BBBBBB shall comply with the requirements in 40 C.F.R. §§63.11092(d)(1) through (4).

- (1) Operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the operating parameter value for the parameters described in 40 C.F.R. §63.11092(b)(1).
- (2) In cases where an alternative parameter pursuant to 40 C.F.R. §63.11092(b)(1)(iv) or 40 C.F.R. §63.11092 (b)(5)(i) is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value.

- (3) Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as appropriate, shall constitute a violation of the emission standard in 40 C.F.R. §63.11088(a), except as specified in 40 C.F.R. §63.11092(d)(4).
- (4) For the monitoring and inspection, as required under 40 C.F.R. §§63.11092(b)(1)(i)(B)(2) and (b)(1)(iii)(B)(2), malfunctions that are discovered shall not constitute a violation of the emission standard in 40 C.F.R. §63.11088(a) if corrective actions as described in the monitoring and inspection plan are followed. The owner or operator must:
 - (i) Initiate corrective action to determine the cause of the problem within 1 hour;
 - (ii) Initiate corrective action to fix the problem within 24 hours;
 - (iii) Complete all corrective actions needed to fix the problem as soon as practicable consistent with good air pollution control practices for minimizing emissions;
 - (iv) Minimize periods of start-up, shutdown, or malfunction; and
 - (v) Take any necessary corrective actions to restore normal operation and prevent the recurrence of the cause of the problem.

[40 C.F.R. §63.11092(d);45CSR34] (T Load and OXIDIZER)

- 5.2.9. When loading barges with gasoline or crude, the MLDOX shall be operated above the minimum temperature established during the performance test demonstrating the device achieves a minimum control efficiency of 98% for VOCs. For naphtha loading, the minimum operating temperature is 899 °F. For light crude loading, the minimum operating temperature is 1346 °F. The MLDOX shall be equipped with two (2) thermocouples with the second thermocouple serving as backup. The thermocouples shall have an accuracy/precision of at least $\pm 0.75\%$. The MLDOX temperature shall be continuously monitored and recorded using an electronic monitoring system. Continuous means at least one data point is recorded in each quadrant of the hour with a 1-hour block averaging period. MLDOX startup/shutdown periods are excluded from averaging. An excursion shall be defined as a temperature below the minimum operating temperature. Excursions trigger a system inspection and corrective action.

Monitoring equipment shall be installed and verified according to the manufacturer's specifications.

[45CSR§30-5.1.c; 40 C.F.R. 64.6(c)] (MLDOX)

- 5.2.10. When the Ammonia Destruction Unit (ADU) is in operation, the NH3OX shall be operated above the minimum temperature established during the performance test demonstrating the device achieves a minimum control efficiency of 99.9% for VOCs. The minimum operating temperature is 1630 °F. The NH3OX shall be equipped with two (2) thermocouples with the second thermocouple serving as backup. The thermocouples shall have an accuracy/precision of at least $\pm 0.75\%$. The NH3OX temperature shall be continuously monitored and recorded using an electronic monitoring system. Continuous means at least one data point is recorded in each quadrant of the hour with a 3-hour block averaging period. ADU/NH3DOX startup/shutdown periods are excluded from averaging. An excursion shall be defined as a temperature below the minimum operating temperature. Excursions trigger a system inspection and corrective action.

Monitoring equipment shall be installed and verified according to the manufacturer's specifications.

[45CSR§30-5.1.c; 40 C.F.R. 64.6(c)] (NH3OX)

- 5.2.11. **Commencement of operation.** The owner or operator shall conduct the monitoring required under this part upon issuance of a part 70 or 71 permit that includes such monitoring, or by such later date specified in the permit pursuant to §64.6(d).
[45CSR§30-5.1.c; 40 C.F.R. §64.7(a)] (MLDOX and NH3OX)
- 5.2.12. **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 C.F.R. §64.7(b)] (MLDOX and NH3OX)
- 5.2.13. **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 this part, 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 C.F.R. §64.7(c)] (MLDOX and NH3OX)
- 5.2.14. **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 C.F.R. §64.7(d)] (MLDOX and NH3OX)**
- 5.2.15. **Documentation of need for improved monitoring.** After approval of monitoring under this part, 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 C.F.R. §64.7(e)] (MLDOX and NH3OX)

5.2.16. Quality improvement plan (QIP) requirements.

- a. Based on the results of a determination made under §64.7(d)(2), the Administrator or the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with §64.6(c)(3), the part 70 or 71 permit may specify an appropriate threshold, such as an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, for requiring the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.
- b. Elements of a QIP:
 1. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.
 2. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:
 - i. Improved preventive maintenance practices.
 - ii. Process operation changes.
 - iii. Appropriate improvements to control methods.
 - iv. Other steps appropriate to correct control performance.
 - v. More frequent or improved monitoring (only in conjunction with one or more steps under paragraphs (b)(2)(i) through (iv) of this section).
- c. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.
- d. Following implementation of a QIP, upon any subsequent determination pursuant to §64.7(d)(2) the Administrator or the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:
 1. Failed to address the cause of the control device performance problems; or
 2. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.
- e. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

[45CSR§30-5.1.c; 40 C.F.R. §64.8] (MLDOX and NH3OX)

5.3. Testing Requirements

- 5.3.1. The hydrogen sulfide concentrations of the sour gas stream used to determine daily compliance with Section 5.1.3. shall be determined on days when the fuel gas treatment system is not operating by running 2-hour samples of the hydrogen sulfide content of the water entering and exiting the sour water stripper unit. At least three (3) 2-hour samples shall be taken during each 24-hour period at approximately 8-hour intervals.
[CO-SIP-95-1 - Condition V.9. (SIPed)]

- 5.3.2. The permittee shall conduct an initial performance test of MLDOX to demonstrate compliance with the control efficiency provided in the Emissions Unit Table (minimum of 98%), Section 1.1, and shall establish operating parameters in accordance with the most recent performance test.
[45CSR13: Permit R13-2334, 5.3.1. (00A-04)]

- 5.3.3. The permittee shall meet all applicable performance tests requirements of 40 CFR §60.8 for MLDOX, OXIDIZER, and NH3OX.
[45CSR16, 40 CFR §60.8, 45CSR13: R13-2334, 5.3.2]

- 5.3.4. The permittee shall calculate an annual estimate of HAP emissions from gasoline and light crude oil from marine tank vessel loading operations. Emission estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source.

The recordkeeping requirements of 40 CFR §63.567(j)(4) and the emission estimation requirements of 40 CFR §63.565(l) apply to existing sources with emissions less than 10 and 25 tons.

[45CSR34, 40 CFR §§63.560(a)(3) and 63.565(l), 45CSR13: R13-2334, 5.3.4]

- 5.3.5. Immediately before the performance test required to determine compliance with 40 C.F.R. §§60.502 (b), (c), and (h), the owner or operator shall use Method 21 to monitor for leakage of vapor all potential sources in the terminal's vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 10,000 ppm (as methane) or greater before conducting the performance test.

[40 C.F.R. §60.503(b); 45CSR16] (T Load)

- 5.3.6. The owner or operator shall determine compliance with the standards in §60.502 (b) and (c) as follows:

1. The performance test shall be 6 hours long during which at least 300,000 liters of gasoline is loaded. If this is not possible, the test may be continued the same day until 300,000 liters of gasoline is loaded or the test may be resumed the next day with another complete 6-hour period. In the latter case, the 300,000-liter criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.
2. If the vapor processing system is intermittent in operation, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.
3. The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K \sum_{i=1}^n (V_{esi} C_{ei}) / L 10^6$$

where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{esi} = volume of air-vapor mixture exhausted at each interval “i”, scm.

C_{ei} = concentration of total organic compounds at each interval “i”, ppm.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

i = emission testing interval of 5 minutes.

K = density of calibration gas, 1.83×10^6 for propane and 2.41×10^6 for butane, mg/scm.

4. The performance test shall be conducted in intervals of 5 minutes. For each interval “i”, readings from each measurement shall be recorded, and the volume exhausted (V_{esi}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.
5. The following methods shall be used to determine the volume (V_{esi}) air-vapor mixture exhausted at each interval:
 - i. Method 2B shall be used for combustion vapor processing systems.
 - ii. Method 2A shall be used for all other vapor processing systems.
6. Method 25A or 25B shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. The calibration gas shall be either propane or butane. The owner or operator may exclude the methane and ethane content in the exhaust vent by any method (e.g., Method 18) approved by the Administrator.
7. To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

[40 C.F.R. §60.503(c); 45CSR16] (T Load)

- 5.3.7. The owner or operator shall determine compliance with the standard in §60.502(h) as follows:

1. A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ± 2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.

2. During the performance test, the pressure shall be recorded every 5 minutes while a gasoline truck is being loaded; the highest instantaneous pressure that occurs during each loading shall also be recorded. Every loading position must be tested at least once during the performance test.

[40 C.F.R. §60.503(d); 45CSR16] (T Load)

- 5.3.8. The MLDOX and NH3OX thermocouples shall be inspected no less than once per year to verify accuracy according to the manufacturer's recommendations.
[45CSR§30-5.1.c; 40 C.F.R. §64.6(c)] (MLDOX and NH3OX)

5.4. Recordkeeping Requirements

- 5.4.1. To determine compliance with the loading emission limits set forth in Section 5.1.9., the permittee shall keep a monthly record of the volume and type of each product/product type loaded at each truck loading station and marine barge loading station and whether or not the VOC emissions were controlled using the control devices [OXIDIZER or MLDOX]. AP-42 emission factors for flares and transportation and marketing of petroleum liquids (Chapter 5.2, 1/95) or test data may be used to estimate emissions.
[45CSR13: Permit R13-2334, 5.4.1.]

- 5.4.2. To determine compliance with the annual benzene emission limit set forth in Section 5.1.9., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of benzene present in petroleum liquids processed and transported at the facility. The following equation shall be to determine monthly and yearly emissions.

$$\text{Benzene Emissions (tpm or tpy)} = (\text{Total VOCs (tpm or tpy)}) \times (\text{Actual Benzene Vapor Weight \%})$$

Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.
[45CSR13: Permit R13-2334, 5.4.2.]

- 5.4.3. To demonstrate compliance with the operational limit for the main/sour gas flare [F1] established in section 5.1.10., the permittee shall maintain records of the hours that non-pilot emissions were sent to the flare. The annual limit shall be recorded on a 12-month rolling total basis.
[45CSR13: Permit R13-2334, 5.4.3.]

- 5.4.4. The permittee shall meet all applicable notification and record keeping requirements of 40 CFR §60.7 for OXIDIZER, MLDOX, and NH3OX.
[45CSR16, 40 CFR §60.7, 45CSR13: Permit R13-2334, 5.4.4.]

- 5.4.5. The permittee shall retain records of the emissions estimates determined in 40 CFR §63.565(l) and requirement 5.3.4. of this permit and their actual throughputs by commodity for gasoline and light crude oil, for 5 years.
[45CSR34, 40 CFR §§63.560(a)(3) and 63.567(j)(4), 45CSR13: Permit R13-2334, 5.4.6.]

- 5.4.6. The tank truck vapor tightness documentation required under §60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.
[40 C.F.R. §60.505(a); 45CSR16] (T Load)

5.4.7. The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:

1. Test title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.
2. Tank owner and address.
3. Tank identification number.
4. Testing location.
5. Date of test.
6. Tester name and signature.
7. Witnessing inspector, if any: Name, signature, and affiliation.
8. Test results: Actual pressure change in 5 minutes, mm of water (average for 2 runs).

[40 C.F.R. §60.505(b); 45CSR16] (T Load)

5.4.8. A record of each monthly leak inspection required under §60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:

1. Date of inspection.
2. Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).
3. Leak determination method.
4. Corrective action (date each leak repaired; reasons for any repair interval in excess of 15 days).
5. Inspector name and signature.

[40 C.F.R. §60.505(c); 45CSR16] (T Load)

5.4.9. The terminal owner or operator shall keep documentation of all notifications required under §60.502(e)(4) on file at the terminal for at least 2 years.

[40 C.F.R. §60.505(d); 45CSR16] (T Load)

5.4.10. As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 40 C.F.R. §§60.505(a), (c), and (d) of this section, an owner or operator may comply with the requirements in either 40 C.F.R. §§60.505(e)(1) or (2).

1. An electronic copy of each record is instantly available at the terminal.
 - i. The copy of each record in 40 C.F.R. §§60.505(e)(1) is an exact duplicate image of the original paper record with certifying signatures.

- ii. The permitting authority is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R.§§60.505(e)(1).
2. For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.
 - i. The copy of each record in 40 C.F.R.§§60.505(e)(2) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The permitting authority is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R.§§60.505(e)(2).

[40 C.F.R. §60.505(e); 45CSR16] (T Load)

- 5.4.11. The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.

[40 C.F.R. §60.505(f); 45CSR16] (T Load)

- 5.4.12. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as specified in paragraphs (b)(1) through (3) of 40 C.F.R. §63.11094.
1. Annual certification testing performed under §63.11092(f)(1) and periodic railcar bubble leak testing performed under §63.11092(f)(2).
 2. The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:
 - i. Name of test: Annual Certification Test—Method 27 or Periodic Railcar Bubble Leak Test Procedure.
 - ii. Cargo tank owner's name and address.
 - iii. Cargo tank identification number.
 - iv. Test location and date.
 - v. Tester name and signature.
 - vi. Witnessing inspector, if any: Name, signature, and affiliation.
 - vii. Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.
 - viii. Test results: Test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

3. If you are complying with the alternative requirements in §63.11088(b), you must keep records documenting that you have verified the vapor tightness testing according to the requirements of the Administrator.

[40 C.F.R. §63.11094(b);45CSR34] (T Load)

- 5.4.13. As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 40 C.F.R. §63.11094(b), an owner or operator may comply with the requirements in either 40 C.F.R. §63.11094(c)(1) or (c)(2).
 1. An electronic copy of each record is instantly available at the terminal.
 - i. The copy of each record in 40 C.F.R. §63.11094(c)(1) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The Administrator is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R. §63.11094(c)(1).
 2. For facilities that use a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by the Administrator's delegated representatives during the course of a site visit, or within a mutually agreeable time frame
 - i. The copy of each record in 40 C.F.R. §63.11094(c)(2) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The Administrator is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R. §63.11094(c)(2).

[40 C.F.R. §63.11094(c);45CSR34] (T Load)

- 5.4.14. Each owner or operator subject to the equipment leak provisions of §63.11089 shall prepare and maintain a record describing the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under §63.11089, the record shall contain a full description of the program.

[40 C.F.R. §63.11094(d);45CSR34] (T Load)

- 5.4.15. Each owner or operator of an affected source subject to equipment leak inspections under §63.11089 shall record in the log book for each leak that is detected the information specified in 40 C.F.R. §§63.11094(e)(1) through (7).
 1. The equipment type and identification number.
 2. The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, or smell).
 3. The date the leak was detected and the date of each attempt to repair the leak.
 4. Repair methods applied in each attempt to repair the leak.

5. “Repair delayed” and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak.
6. The expected date of successful repair of the leak if the leak is not repaired within 15 days.
7. The date of successful repair of the leak.

[40 C.F.R. §63.11094(e);45CSR34] (T Load)

5.4.16. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:

1. Keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.11092(b) or §63.11092(e). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.
2. Record and report simultaneously with the Notification of Compliance Status required under §63.11093(b):
 - i. All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under §63.11092(b) or §63.11092(e); and
 - ii. The following information when using a flare under provisions of §63.11(b) to comply with §63.11087(a):
 - A. Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and
 - B. All visible emissions (VE) readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under §63.11092(e)(3).
3. Keep an up-to-date, readily accessible copy of the monitoring and inspection plan required under §63.11092(b)(1)(i)(B)(2) or §63.11092(b)(1)(iii)(B)(2).
4. Keep an up-to-date, readily accessible record of all system malfunctions, as specified in §63.11092(b)(1)(i)(B)(2)(v) or §63.11092(b)(1)(iii)(B)(2)(v).
5. If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in §63.11092(b), the owner or operator shall submit a description of planned reporting and recordkeeping procedures.

[40 C.F.R. §63.11094(f);45CSR34] (T Load)

5.4.17. Each owner or operator of an affected source under this subpart shall keep records as specified in 40 C.F.R. §63.11094(g)(1) and (2).

1. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
2. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.11085(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 C.F.R. §63.11094(g);45CSR34] (T Load)

5.4.18. General recordkeeping requirements.

1. The owner or operator shall comply with the recordkeeping requirements specified in §70.6(a)(3)(ii) of this chapter. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
2. 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 C.F.R. §64.9(b)] (MLDOX and NH3OX)

- 5.4.19. The temperature data for MLDOX and NH3OX shall be recorded and maintained in an electronic database and records shall be maintained for at least 5 years.

[45CSR§30-5.1.c; 40 C.F.R. §64.9(b)] (MLDOX and NH3OX)

5.5. Reporting Requirements

- 5.5.1. For the Main Flare [F1], the permittee shall comply with the reporting requirements of 40 CFR Part 60, Subpart Ja.

[45CSR16, 40 CFR§60.108a, 45CSR13: Permit R13-2334, 5.5.1.]

- 5.5.2. For the Sour Gas Flare [F2], the permittee shall comply with the reporting requirements of 40 CFR 60, Subpart J.

[45CSR16, 40 CFR §60.107(f), 45CSR13: Permit R13-2334, 5.5.2.]

- 5.5.3. The permittee shall meet all applicable reporting requirements of 40 CFR §60.19 for OXIDIZER, MLDOX, and NH3OX.

[45CSR16, 40 CFR §60.19, 45CSR13 - Permit R13-2334 - 5.5.3.]

- 5.5.4. Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:

1. For loading racks, each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility.

2. For equipment leak inspections, the number of equipment leaks not repaired within 15 days after detection.

[40 C.F.R. §§63.11095(a)(2) and (3);45CSR34] (T Load)

5.5.5. Each owner or operator of an affected source subject to the control requirements of this subpart shall submit an excess emissions report to the Administrator at the time the semiannual compliance report is submitted. Excess emissions events under this subpart, and the information to be included in the excess emissions report, are specified in 40 C.F.R. §§63.11095(b)(1) through (5).

1. Each instance of a non-vapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.
2. Each reloading of a non-vapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.11094(b).
3. Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.11092(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.
4. Each instance in which malfunctions discovered during the monitoring and inspections required under §63.11092(b)(1)(i)(B)(2) and (b)(1)(iii)(B)(2) were not resolved according to the necessary corrective actions described in the monitoring and inspection plan. The report shall include a description of the malfunction and the timing of the steps taken to correct the malfunction.
5. For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:
 - i. The date on which the leak was detected;
 - ii. The date of each attempt to repair the leak;
 - iii. The reasons for the delay of repair; and
 - iv. The date of successful repair.

[40 C.F.R. §63.11095(b); 45CSR34] (T Load)

5.5.6. Each owner or operator of a bulk gasoline plant or a pipeline pumping station shall submit a semiannual excess emissions report, including the information specified in 40 C.F.R. §63.11095(a)(3) and (b)(5), only for a 6-month period during which an excess emission event has occurred. If no excess emission events have occurred during the previous 6-month period, no report is required.

[40 C.F.R. §63.11095(c); 45CSR34] (T Load)

5.5.7. Each owner or operator of an affected source under this subpart shall submit a semiannual report including the number, duration, and a brief description of each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected

source to minimize emissions in accordance with §63.11085(a), including actions taken to correct a malfunction. The report may be submitted as a part of the semiannual compliance report, if one is required. Owners or operators of affected bulk plants and pipeline pumping stations are not required to submit reports for periods during which no malfunctions occurred.

[40 C.F.R. §63.11095(d); 45CSR34] (T Load)

5.5.8. **General reporting requirements.**

1. On and after the date specified in §64.7(a) by which the owner or operator must use monitoring that meets the requirements of this part, the owner or operator shall submit monitoring reports to the permitting authority in accordance with §70.6(a)(3)(iii) of this chapter.
2. A report for monitoring under this part shall include, at a minimum, the information required under §70.6(a)(3)(iii) of this chapter and the following information, as applicable:
 - i. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
 - ii. 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
 - iii. A description of the actions taken to implement a QIP during the reporting period as specified in §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 C.F.R. §64.9(a)] (MLDOX and NH3OX)

5.6. **Compliance Plan**

- 5.6.1. None.

6.0 Other Source Requirements [CDU, MEK-TOL, DHT-FUG, ISOM, UNIFINER, ADU, PL-FUG, and YNGL-FUG]

6.1. Limitations and Standards

- 6.1.1. Crude oil charge rate into the crude oil distillation unit shall not exceed 961,775 barrels per month and 9,617,750 barrels per year.

[45CSR13: Permit R13-2334, 6.1.1.]

- 6.1.2. Fugitive emissions of VOC's (MEK and Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 10.26 TPY. Fugitive emissions of HAPs (Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 5.09 TPY.

[45CSR13: Permit R13-2334, 6.1.2.]

- 6.1.3. The facility shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions:

a. **Leak Definition for Valves.** The facility shall utilize an internal leak definition of 500 ppm VOCs for the Refinery valves, excluding pressure relief devices.

b. **Leak Definition for Pumps.** The facility shall utilize an internal leak definition of 2000 ppm VOCs for the Refinery pumps.

[45CSR13: Permit R13-2334, 6.1.3.]

- 6.1.4. Fugitive emissions from the Diesel Hydrotreater [DHT-FUG], the Ammonia Destruction Unit [ADUFUG], the Platformer Expansion Unit [PL-FUG], and the Y-Grade NGL Unit [YNGL-FUG] shall not exceed the following:

Pollutant	DHT-FUG Fugitive Emissions	ADUFUG Fugitive Emissions	PL-FUG Fugitive Emissions	YNGL-FUG Fugitive Emissions
	ton/yr	ton/yr	ton/yr	ton/yr
VOC	13.20	0.34	0.60	0.94
Toluene	0.003	n/a	n/a	n/a
Ethyl Benzene	0.001	n/a	n/a	n/a
Xylene	0.04	n/a	n/a	n/a
Pentane	n/a	0.05	n/a	n/a
Hexane	n/a	0.02	0.04	0.03

[45CSR13: Permit R13-2334, 6.1.4.]

- 6.1.5. Fugitive emissions from the ISOM Unit shall not exceed 3.72 tpy VOC's and 0.85 tpy total HAP's.

[45CSR13: Permit R13-2334, 6.1.5.]

- 6.1.6. The permittee shall comply with the VOC equipment leak requirements of 40 CFR Part 60 Subpart VVa (as required by the applicability of 40 CFR Part 60, Subpart GGGa) of affected facilities for which construction, reconstruction, or modification commenced after November 7, 2006 and Section 8.0 of this permit.

[45CSR13: Permit R13-2334, 6.1.6.]

6.2. Monitoring Requirements

6.2.1. None.

6.3. Testing Requirements

6.3.1. None.

6.4. Recordkeeping Requirements

6.4.1. To determine compliance with the crude oil charge rate limits set forth in Section 6.1.1., the permittee shall keep daily records along with monthly and yearly totals of the amount of crude oil charged to the crude oil distillation unit. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13: Permit R13-2334, 6.2.1.]

6.4.2. To determine compliance with VOC fugitive emission rate limits set forth in Sections 6.1.2., 6.1.4., 6.1.5., and the internal leak definitions set forth in Section 6.1.3, the permittee shall comply with the requirements of 40 CFR Part 60 Subpart VV and apply the following Leak Detection and Repair (LDAR) program enhancements:

Emission Estimates. The permittee may use an enhanced LDAR program for controlling and estimating emissions on a monthly and yearly basis for the Solvent Dewaxing Unit. The permittee may use EPA's Correlation Approach, published in EPA's Protocol for Equipment Leak Emission Estimates, with measured screening values and hours of operation to determine compliance with the emission limits.

[45CSR13: Permit R13-2334, 6.2.2.]

6.5. Reporting Requirements

6.5.1. None.

6.6. Compliance Plan

6.6.1. None.

7.0 Tank Requirements

7.1. Limitations and Standards

7.1.1. Storage tanks are limited to the raw material/ product type and throughput provided in the table below:

Tank ID No.	Raw Material/Product Type and Throughput (Mgal gallons per year)
4000, 4001, 4060, 4061, and 4072	crude oil (802,264. ~~89~~ ~~,890~~ Mgal)
4062, 4063	crude oil and light crude oil w/vapor pressure up to 11.0 psia (306,600, ~~000~~)
4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, 4052, 4053, 4070, and 4071	gasoline or ethanol (325,070. ~~903~~ ~~,903~~)
4002, 4003, 4009, 4011, 4054, 4055, 4056, 4057, and 4073	heavy products or kerosene (406,459. ~~76~~ ~~,760~~)
4007, 4008, 4010, 4017, 4018, 4019, 4020, 4021, 4022, 4023, 4024, 4025, 4026, 4027, 4028, 4029, 4030, 4031, 4032, 4033, 4034, 4035, 4036, 4037, 4038, 4039, 4040, 4041, 4042, 4043, 4044, 4045, 4046, 4047, 4048, 4051, 4103, and 4104	heavy products (609,920. ~~249~~ ~~,249~~)
V-4002 and V-4003	Natural Gas Liquids

[45CSR13: Permit R13-2334, 7.1.1.]

7.1.2. Combined emissions from the tanks listed in section 7.1.1 shall not exceed the following:

Pollutant	Emission Rate	
	TPM	TPY
Total VOC	6.03	60.29
Benzene	0.09	0.85
Total HAP	0.69	6.86

[45CSR13: Permit R13-2334, 7.1.2.]

7.1.3. Fixed roof Tanks 4012 and 4013 shall be equipped with internal floating roofs to minimize emissions of VOC's.

[45CSR13: Permit R13-2334, 7.1.3.]

7.1.4. The following requirements apply to Tanks 4001, 4002, 4003, 4004, 4005, 4006, 4014, 4015, 4016:

- a. Each and every slotted guidepole that passes through the floating roof shall be equipped with one of the following: a pole float system; an alternate control technology that has an emission factor less than or equal to the emission factor for a pole float system; a pole sleeve system; an internal sleeve emission control system; a solid guidepole system; a flexible enclosure system; or
- b. In the alternative, the Permittee may elect to cover an external floating roof tank with a fixed roof mounted on the tank above the external floating roof, or remove the tank from the service storing liquids subject to NSPS Ka or Kb, modify the permit for that tank, and represent to the West Virginia Division of Air Quality that the tank will not be used to store certain petroleum liquids or volatile organic liquids.

- c. For systems that use a sliding cover, the sliding cover shall be in place over the slotted-guidepole opening in the floating roof at all times, except, when the sliding cover must be removed for access. If the control technology used includes a guidepole float, the float shall be floating within the guidepole at all times except when it must be removed for access to the stored liquid or when the tank is empty.
- d. The permittee shall visually inspect the deck fitting for the slotted guidepole at least once every ten (10) years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device has defects, or if a gap that is more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material.
- e. Tanks taken out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are taken out of service. Tanks taken out of service must have in place, prior to being put back into service, all controls necessary to remain below the emission limits set forth by the current version of permit R13-2334

[45CSR13: R13-2334, 7.1.4., 7.1.5.]

- 7.1.5. The following 40 CFR 60 Subpart K requirements apply to Tanks 4036, 4037, 4038, and 4039:

The owner or operator of any storage vessel to which 40 CFR Part 60 subpart K applies shall store petroleum liquids as follows: if the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

[40 CFR §60.112(a)(1) and 45CSR§16-4.1.; 45CSR13: Permit R13-2334, 7.1.6.]

- 7.1.6. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, 4046:

The owner or operator of each storage vessel to which 40 CFR Part 60 Subpart Ka applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

- 1. An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in 40 CFR §60.112a (a)(1)(ii)(D), the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
 - i. The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:
 - A. The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm² per meter of tank diameter (10.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

- B. The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).
- C. One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.
- D. There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
- ii. The secondary seal is to meet the following requirements:
 - A. The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in 40 CFR §60.112a (a)(1)(ii)(B).
 - B. The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.
 - C. There are to be no holes, tears or other openings in the seal or seal fabric.
 - D. The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.
- iii. Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in 40 CFR §60.112a (a)(1)(iv). Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.
- iv. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.
- 2. A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set

to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

3. A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.
4. A system equivalent to those described in 40 CFR §60.112a (a)(1), (a)(2), or (a)(3) as provided in 40 CFR §60.114a.

[40 C.F.R. §60.112a(a) and 45CSR16]

7.1.7. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070 and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

- a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ 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 m³ but less than 151 m³ 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:

1. A fixed roof in combination with an internal floating roof meeting the following specifications:
 - i. The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.
 - ii. Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:
 - A. A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.
 - B. Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.
 - C. A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

- iii. Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.
 - iv. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.
 - v. Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
 - vi. Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.
 - vii. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.
 - viii. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.
 - ix. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.
2. An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:
- i. Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.
 - A. The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in 40 CFR §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.
 - B. The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in 40 CFR §60.113b(b)(4).
 - ii. Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed

on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

- iii. The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
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 40 CFR 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 (40 CFR §60.18) of the General Provisions.
4. A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) above as provided in 40 CFR §60.114b.
- b. The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:
 1. A closed vent system and control device as specified in 40 CFR §60.112b(a)(3).
 2. A system equivalent to that described in paragraph (b)(1) as provided in 40 CFR §60.114b of this subpart.

[40 CFR §§60.112b(a) and (b), 45CSR§16-4 .1., 45CSR13: Permit R13-2334, 7.1.7.]

- 7.1.8. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 60 Subpart Kb including but not limited to the following:
 - a. Alternative means of compliance—(1) Option to comply with part 65. Owners or operators may choose to comply with 40 CFR Part 65, Subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR Part 65, Subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

[40 CFR §60.110b(e), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.8.]

- 7.1.9. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 65 Subparts C and G including but not limited to the following:

- a. Storage vessel requirements. The owner or operator expressly referenced to this subpart from Subpart C of this part shall comply with the following requirements, as applicable:

Route to a fuel gas system or process. Owners or operators subject to §65.42(b)(6) who route storage vessel emissions to a fuel gas system or to a process shall meet the requirements in §65.144 and the monitoring, recordkeeping, and reporting requirements referenced therein. No other provisions of this subpart apply to storage vessel emissions being routed to a fuel gas system or to a process.

[40 CFR §65.142(a)(3), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(a)]

- b. *Route to process or fuel gas system.* Route the emissions to a process or a fuel gas system as specified in §65.142(a)(3). Whenever the owner or operator bypasses the fuel gas system or process, the owner or operator shall comply with the recordkeeping requirement in §65.163(b)(3). Bypassing is permitted if the owner or operator complies with one or more of the following conditions:
- i. The liquid level in the storage vessel is not increased;
 - ii. The emissions are routed through a closed vent system to a control device complying with paragraph (b)(4) or (5) of this section; or
 - iii. The total aggregate amount of time during which the emissions bypass the fuel gas system or process during the calendar year without being routed to a control device, for all reasons (except startups/shutdowns/malfunctions or product changeovers of flexible operation units and periods when the storage vessel has been emptied and degassed), does not exceed 240 hours.

[40 CFR §65.42(b)(6), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(b)]

- c. Except during periods of startup, shutdown, and malfunction as specified in §65.3(a), the fuel gas system or process shall be operating at all times when regulated material emissions are routed to it.

[40 CFR §65.144(a)(1), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(c)]

- 7.1.10. You must meet each emission limit and management practice in Table 1 to 40 CFR 63 Subpart BBBBBB that applies to your gasoline storage tank.

If you own or operate ...	Then you must ...
2. A gasoline storage tank with a capacity of greater than or equal to 75 m ³ and not meeting any of the criteria specified in item 1 of this Table	(a) Reduce emissions of total organic HAP or TOC by 95 weight-percent with a closed vent system and control device, as specified in §60.112b(a)(3) of this chapter; or
	(b) Equip each internal floating roof gasoline storage tank (4012, 4013, and 4050) according to the requirements in §60.112b(a)(1) of this chapter, except for the secondary seal requirements under §60.112b(a)(1)(ii)(B) and the requirements in §60.112b(a)(1)(iv) through (ix) of this chapter; and
	(c) Equip each external floating roof gasoline storage tank (4004, 4005, 4006, 4014, 4015, 4016, and 4071) according to the requirements in §60.112b(a)(2) of this chapter, except that the requirements of §60.112b(a)(2)(ii) of this chapter shall only be required if such storage tank does not currently meet the requirements of §60.112b(a)(2)(i) of this chapter; or

If you own or operate ...	Then you must ...
	(d) Equip and operate each internal and external 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), and equip each external floating roof gasoline storage tank according to the requirements of §63.1063(a)(2) if such storage tank does not currently meet the requirements of §63.1063(a)(1).
[40 C.F.R. §63.11087(a); Table 1 to 40 C.F.R 63 Subpart BBBBBB, 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)	

7.2. Monitoring Requirements

- 7.2.1. Compliance with Section 7.1.4. may be determined by visual inspection by the Director or a duly authorized representative of the Director.

[45CSR13: Permit R13-2334, 7.2.1.]

- 7.2.2. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

The owner or operator of each storage vessel as specified in 40 CFR §60.112b(a) shall meet the requirements of paragraph a., b., or c. of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of 40 CFR §60.112b.

- a. After installing the control equipment required to meet 40 CFR §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:
 1. Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.
 2. For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in 40 CFR §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.
 3. For vessels equipped with a double-seal system as specified in 40 CFR §60.112b(a)(1)(ii)(B) :

- i. Visually inspect the vessel as specified in paragraph a.4. of this section at least every 5 years; or
 - ii. Visually inspect the vessel as specified in paragraph a.2. of this section.
4. Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs a.2. and a.3.ii. of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph a.3.i. of this section.
5. Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs a.1. and a.4. of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph a.4. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.
- b. After installing the control equipment required to meet 40 CFR §60.112b(a)(2) (external floating roof), the owner or operator shall:
 1. Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.
 - i. Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.
 - ii. Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.
 - iii. If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs b.1.i. and b.1.ii. of this section.
 2. Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

- i. Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - ii. Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.
 - iii. The total surface area of each gap described in paragraph b.2.ii. of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
3. Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph b.4. of this section.
4. Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 40 CFR §60.113b(b)(4) (i) and (ii).
5. Notify the Administrator 30 days in advance of any gap measurements required by paragraph b.1. of this section to afford the Administrator the opportunity to have an observer present.
6. Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.
 - i. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.
 - ii. For all the inspections required by paragraph b.6. of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph b.6. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.
- c. 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.

1. 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.
 - 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 40 CFR Part 60 subpart K, 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).
2. 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 c.1. of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

- d. The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in 40 CFR §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, 40 CFR §60.18 (e) and (f).

[40 C.F.R. §60.113b, 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.2.2.]

7.2.3. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, and 4046:

- a. Except as provided in 40 CFR §60.8(b) compliance with the standard prescribed in 40 CFR §60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in 40 CFR §60.114a.
 1. The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:
 - i. Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:
 - A. For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

- B. For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.
 - C. If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs 40 CFR §§60.113a(a)(1)(i)(A) and (a)(1)(i)(B).
 - D. Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by 40 CFR §60.113a(a)(1)(ii) and the calculation required by 40 CFR 60.113a(a)(1)(iii).
 - E. If either the seal gap calculated in accord with 40 CFR §60.113a (a)(1)(iii) or the measured maximum seal gap exceeds the limitations specified by 40 CFR §60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of 40 CFR §60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of 40 CFR §60.112a.
- ii. Determine gap widths in the primary and secondary seals individually by the following procedures:
 - A. Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - B. Measure seal gaps around the entire circumference of the tank in each place where a 1/8" diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.
 - C. The total surface area of each gap described in 40 CFR §60.113a (a)(1)(ii)(B) shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
 - iii. Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in 40 CFR §60.112a(a)(1)(i) and §60.112a(a)(1)(ii).
 - iv. Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.
- 2. The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

- i. Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.
- ii. The manufacturer's design specifications and estimated emission reduction capability of the system.
- iii. The operation and maintenance plan for the system.
- iv. Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

[40 CFR §60.113a and 45CSR16]

7.2.4. The following 40 CFR 60 Subpart Kb requirements apply to Tanks V-4002 and V-4003:

- (e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 - (1) For 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 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.
 - (2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - (i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
 - (ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.
 - (3) For other liquids, the vapor pressure:
 - (i) May be obtained from standard reference texts, or
 - (ii) Determined by ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17); or
 - (iii) Measured by an appropriate method approved by the Administrator; or
 - (iv) Calculated by an appropriate method approved by the Administrator.

[40 CFR §60.116b(e) and 45CSR16]

7.3. Testing Requirements

- 7.3.1. Each owner or operator subject to the emission standard in §63.11087 for gasoline storage tanks shall comply with the requirements in 40 C.F.R. §§63.11092(e)(1) through (3).
- (1) If your gasoline storage tank is equipped with an internal floating roof, you must perform inspections of the floating roof system according to the requirements of 40 C.F.R. §60.113b(a) if you are complying with option 2(b) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB, or according to the requirements of 40 C.F.R. §63.1063(c)(1) if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB. **(4012, 4013, and 4050)**
 - (2) If your gasoline storage tank is equipped with an external floating roof, you must perform inspections of the floating roof system according to the requirements of 40 C.F.R. §60.113b(b) if you are complying with option 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB, or according to the requirements of 40 C.F.R. §63.1063(c)(2) if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB. **(4004, 4005, 4006, 4014, 4015, 4016, and 4071)**

[40 C.F.R. §63.11092(e); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.4. Recordkeeping Requirements

- 7.4.1. To determine compliance with the throughput limits set forth in Section 7.1.1. and the VOC emission limit set forth in Section 7.1.2., the permittee shall keep monthly records of throughput of each raw material/product for each tank. These records shall be kept individually, i.e. per tank. AP-42 emission factors for organic liquid storage tanks (Supp. D, Chapter 7.1), may be used to estimate yearly emissions.
[45CSR13: Permit R13-2334, 7.3.1., 45CSR§30-5.1.c.]
- 7.4.2. To determine compliance with the short-term and annual HAP emission limits set forth in Section 7.1.2., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of HAPs present in petroleum liquids processed and transported at the facility. The following equation shall be used to determine monthly and yearly emissions.

HAP Emissions (tpm or tpy) = [(Individual HAP %) x (Actual VOC emissions, obtained from section 7.4.1. (tpm or tpy))]/100

Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13: Permit R13-2334, 7.3.2., 45CSR§30-5.1.c.]

- 7.4.3. The following 40 CFR 60 Subpart K requirements apply to Tanks 4036, 4037, 4038, and 4039:

Except as provided in 40 CFR §60.113(d), the owner or operator subject to 40 CFR Part 60 subpart K shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

[40 CFR §60.113(a), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.3.]

- 7.4.4. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, and 4046:
- Except as provided in 40 CFR §§60.115a (d), the owner or operator subject to 40 CFR Part 60 Subpart Ka shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.
 - Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
 - The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

[40 CFR §§60.115a(a) through (c) and 45CSR16]

- 7.4.5. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

The owner or operator of each storage vessel as specified in 40 CFR §60.112b (a) shall keep records and furnish reports as required by 40 CFR §60.115b (a), (b), or (c) depending upon the control equipment installed to meet the requirements of 40 CFR §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by 40 CFR §60.115b (c) (1), for at least 2 years. The record required by 40 CFR §60.115b (c)(1) will be kept for the life of the control equipment.

- After installing control equipment in accordance with 40 CFR §60.112b (a) (1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.
 - Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR §60.112b (a)(1) and 40 CFR §60.113b (a)(1). This report shall be an attachment to the notification required by 40 CFR §60.7 (a)(3).
 - Keep a record of each inspection performed as required by 40 CFR §§60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).
 - If any of the conditions described in 40 CFR §60.113b (a)(2) are detected during the annual visual inspection required by 40 CFR §60.113b (a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.
 - After each inspection required by 40 CFR §60.113b (a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 40 CFR §60.113b (a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection.

The report shall identify the storage vessel and the reason it did not meet the specifications of 40 CFR §60.112b (a)(1) or 40 CFR §60.113b (a)(3) and list each repair made.

- b. After installing control equipment in accordance with 40 CFR §60.112b (a)(2) (external floating roof), the owner or operator shall meet the following requirements.
 1. Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR §60.112b (a)(2) and 40 CFR §60.113b (b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by 40 CFR §60.7(a)(3).
 2. Within 60 days of performing the seal gap measurements required by 40 CFR §60.113b (b)(1), furnish the Administrator with a report that contains:
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in 40 CFR §§60.113b (b)(2) and (b)(3).
 3. Keep a record of each gap measurement performed as required by 40 CFR §60.113b (b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in 40 CFR §§60.113b (b)(2) and (b)(3).
 4. After each seal gap measurement that detects gaps exceeding the limitations specified by 40 CFR §60.113b (b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in 40 CFR §60.115b (b)(2) and the date the vessel was emptied or the repairs made and date of repair.
- c. 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.
 1. A copy of the operating plan.
 2. A record of the measured values of the parameters monitored in accordance with 40 CFR §60.113b(c)(2).
- d. After installing a closed vent system and flare to comply with 40 CFR §60.112b, the owner or operator shall meet the following requirements.
 1. A report containing the measurements required by 40 CFR §§60.18 (f)(1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by 40 C.F.R. §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

2. Records shall be kept of all periods of operation during which the flare pilot flame is absent.
3. Semiannual reports of all periods recorded under 40 CFR §60.115b (d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

[40 CFR §60.115b, 45CSR§16-4.1.; 45CSR13: Permit R13-2334, 7.3.4.]

- 7.4.6. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, 4071, and 4073:
- a. The owner or operator shall keep copies of all records required by 40 CFR Part 60 Subpart Kb, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section 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 and an analysis showing the capacity of the storage vessel.
 - c. Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa 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.
 - d. Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.
 - e. Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 1. For 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 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.
 2. For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - i. Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference -- see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

- ii. The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.
- f. The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.
 - 1. Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.
 - 2. For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in 40 CFR §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:
 - i. ASTM D2879-83, 96, or 97 (incorporated by reference -- see 40 CFR §60.17); or
 - ii. ASTM D323-82 or 94 (incorporated by reference -- see 40 CFR §60.17); or
 - iii. As measured by an appropriate method as approved by the Administrator.
- g. The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of 40 CFR §60.112b or with emissions reductions equipment as specified in 40 CFR §65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[40 CFR §60.116b, 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.5.]

- 7.4.7. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 65 Subparts C and G including but not limited to the following:
- a. Bypass records for storage vessel emissions routed to a process or fuel gas system. An owner or operator who uses the bypass provisions of §65.144(a)(2) shall keep in a readily accessible location the following records:
 - i. The reason it was necessary to bypass the process equipment or fuel gas system;
 - ii. The duration of the period when the process equipment or fuel gas system was bypassed;
 - iii. Documentation or certification of compliance with the applicable provisions of §65.42(b)(6).

[40 CFR §65.163(b)(3), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(a)]

- b. Vessel dimensions and capacity. Each owner or operator of a storage vessel subject to this subpart shall keep readily accessible records showing the dimensions of the storage vessel and an analysis of the capacity of the storage vessel.

[40 CFR §65.47(b), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(b)]

- c. Regulated source and control equipment startup, shutdown and malfunction records. (1) Records of the occurrence and duration of each startup, shutdown, and malfunction of process equipment or of air pollution control equipment used to comply with this part during which excess emissions (as defined in §65.3(a)(4)) occur.

[40 CFR §65.163(c), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(c)]

- 7.4.8. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 60 Subpart A including but not limited to the following:

- a. Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

- 1. A notification of the date construction (or reconstruction as defined under 40 CFR §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

[40 CFR §60.7(a)(1), 45CSR§16-4.1]

- 7.4.9. Each owner or operator of a bulk gasoline terminal or pipeline breakout station whose storage vessels are subject to the provisions of this subpart shall keep records as specified in 40 C.F.R. §60.115b of this chapter if you are complying with options 2(a), 2(b), or 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBB, except records shall be kept for at least 5 years. If you are complying with the requirements of option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBB, you shall keep records as specified in 40 C.F.R. §63.1065.

[40 C.F.R. §63.11094(a); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.5. Reporting Requirements

- 7.5.1. Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:

- (1) For storage vessels, if you are complying with options 2(a), 2(b), or 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBB, the information specified in 40 C.F.R. §60.115b(a), 40 C.F.R. §60.115b(b), or 40 C.F.R. §60.115b(c), depending upon the control equipment installed, or, if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBB, the information specified in 40 C.F.R. §63.1066.

[40 C.F.R. §63.11095(a); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.6. Compliance Plan

- 7.6.1. None.

8.0 Equipment Leak Detection and Repair Requirements

8.1. Limitations and Standards

8.1.1. **Training.** The permittee shall implement the following training programs at the facility:

- a. For personnel newly assigned to LDAR responsibilities, EWVI shall require LDAR training prior to each employee beginning such work;
- b. For all personnel assigned LDAR responsibilities, EWVI shall provide and require completion of annual LDAR training; and
- c. For all other Refinery operations and maintenance personnel (including contract personnel), EWVI shall provide and require completion of an initial training program that includes instruction on aspects of LDAR that are relevant to the person's duties. Refresher training in LDAR shall be performed on a three-year cycle.

[45CSR13: Permit R13-2334, 8.1.1., 45CSR§30-12.7]

8.1.2. **LDAR Personnel.** The permittee shall establish a program that will hold LDAR personnel accountable for LDAR performance. The permittee shall maintain a position within the facility responsible for LDAR management, with the authority to implement improvements.

[45CSR13: Permit R13-2334, 8.1.2., 45CSR§30-12.7]

8.1.3. **Internal Leak Definition for Valves and Pumps; Compressor Compliance.** The permittee shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions.

- a. **Leak Definition for Valves.** The permittee shall utilize an internal leak definition of 500 ppm VOCs for the valves at the facility, excluding pressure relief devices.
- b. **Leak Definition for Pumps.** The permittee shall utilize an internal leak definition of 2000 ppm VOCs for the pumps at the facility.

[45CSR13: Permit R13-2334, 8.1.3., 45CSR§30-12.7]

8.1.4. **First Attempt at Repairs on Valves.** The permittee shall make a "first attempt" at repair on any valve that has a reading greater than 200 ppm of VOCs, excluding control valves, pumps, and components that LDAR personnel are not authorized to repair. The permittee, or its designated contractor, however, shall re-monitor, within 5 business days, all valves that LDAR personnel attempted to repair. Unless the re-monitored leak rate is greater than the applicable leak definition, no further action will be necessary.

[45CSR13: Permit R13-2334, 8.1.4., 45CSR§30-12.7]

8.1.5. **Delay of Repair.** For any equipment for which the permittee is allowed, under the applicable regulations, to place on the "delay of repair" list for repair:

- a. For all equipment, the permittee shall:

1. Require sign-off by the unit supervisor or shift supervisor that the piece of equipment is technically infeasible to repair without a process unit shutdown, before the component is eligible for inclusion on the “delay of repair” list; and
 2. Include equipment that is placed on the “delay of repair” list in the permittee’s regular LDAR monitoring.
- b. For valves: For valves, other than control valves, leaking at a rate of 10,000 ppm or greater, the permittee shall continue to use its “drill and tap” method for fixing such leaking valves, rather than placing the valve on the “delay of repair” list, unless the permittee can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner. After two unsuccessful attempts to repair a leaking valve through the drill and tap method, the permittee may place the leaking valve on its “delay of repair” list. If a new method develops for repairing such valves, the permittee will advise EPA prior to implementing such new method.
- c. For pumps: For pumps leaking at a rate of 2000 ppm or greater, the permittee shall undertake its best efforts to isolate and repair such pumps with a first attempt at fifteen (15) days.

[45CSR13: Permit R13-2334, 8.1.5., 45CSR§30-12.7]

- 8.1.6. a. 1. The provisions of 40 CFR Part 60 Subpart GGGa apply to affected facilities in petroleum refineries.
2. A compressor is an affected facility.
3. The group of all the equipment (defined in 40 CFR §60.591a) within a process unit is an affected facility.
- b. Any affected facility under 40 CFR §60.590a(a) that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of 40 CFR Part 60 Subpart GGGa.
- c. Addition or replacement of equipment (defined in 40 CFR §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under 40 CFR Part 60 Subpart GGGa.

[45CSR16, 40 CFR §§60.590a (a) through (c)]

- 8.1.7. a. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGGa shall comply with the requirements of 40 CFR §§60.482-1a to 60.482-10a as soon as practicable, but no later than 180 days after initial startup.
- b. For a given process unit, an owner or operator may elect to comply with the requirements of 40 CFR §60.592a (b)(1), (2), or (3) as an alternative to the requirements in 40 CFR §60.482-7a.
1. Comply with 40 CFR §60.483-1a.
 2. Comply with 40 CFR §60.483-2a.
 3. Comply with the Phase III provisions in 40 CFR §63.168, except an owner or operator may elect to follow the provisions in 40 CFR §60.482-7a (f) instead of 40 CFR §63.168 for any valve that is designated as being leakless.

- c. An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of 40 CFR §60.484a.
- d. Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 40 CFR §60.485a except as provided in 40 CFR §60.593a.
- e. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGGa shall comply with the provisions of 40 CFR §§60.486a and 60.487a.

[45CSR16, 40 CFR §60.592a]

- 8.1.8.
- a. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGGa may comply with the following exceptions to the provisions of 40 CFR Part 60 Subpart VVa.
 - b.
 - 1. Compressors in hydrogen service are exempt from the requirements of 40 CFR §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.
 - 2. Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260-73, 91, or 96, E168-67, 77, or 92, or E169-63, 77, or 93 (incorporated by reference as specified in 40 CFR §60.17) shall be used.
 - 3.
 - i. An owner or operator may use engineering judgment rather than procedures in 40 CFR §60.593a (b)(2) to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in 40 CFR §60.593a (b)(2) shall be used to resolve the disagreement.
 - ii. If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in 40 CFR §60.593a (b)(2).
 - c. Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from 40 CFR §§60.482-3a (a) through (e) and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §§60.482-3a (a) through (e) and (h).
 - d. An owner or operator may use the following provision in addition to 40 CFR §60.485a (e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86-78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in 40 CFR §60.17).

- e. Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of 40 CFR §§60.482-2a and 60.482-7a.
- f. Open-ended valves or lines containing asphalt as defined in 40 CFR §60.591a are exempt from the requirements of 40 CFR §§60.482-6a (a) through (c).
- g. Connectors in gas/vapor or light liquid service are exempt from the requirements in 40 CFR §60.482-11a, provided the owner or operator complies with 40 CFR §60.482-8a for all connectors, not just those in heavy liquid service.

[45CSR16, 40 CFR §60.593a]

- 8.1.9. Any affected facility under 40 CFR §60.480a (a) that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of 40 CFR Part 60 Subpart VVa unless other permit requirements require more stringent requirements.

[45CSR13: R13-2334, 8.1.6., 45CSR16, 40 CFR §§60.480a (b)]

Standards: General

- 8.1.10. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall demonstrate compliance with the requirements of 40 CFR §§60.482-1a through 60.482-10a or 40 CFR §60.480a (e) for all equipment within 180 days of initial startup.
- b. Compliance with §§60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.
- c. 1. The permittee may request a determination of equivalence of a means of emission limitation to the requirements of 40 CFR §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in 40 CFR §60.484a.
2. If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of 40 CFR §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, or 60.482-10a, the permittee shall comply with the requirements of that determination.
- d. Equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in 40 C.F.R. §60.486a (e)(5).
- e. Equipment that the permittee designates as being in VOC service less than 300 hr/yr is excluded from the requirements of 40 CFR §§60.482-2a through 60.482-11a if it is identified as required in §60.486a (e) (6) and it meets any of the conditions specified in 40 CFR §§60.482-1a (e) (1) through (3).
1. The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.
2. The equipment is in VOC service only during process malfunctions or other emergencies.

3. The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.
- f. 1. If a dedicated batch process unit operates less than 365 days during a year, the permittee may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in 40 CFR §§60.482-2a, 60.482-7a, and 60.483-2a

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually
25 to <50	Quarterly	Semiannually	Annually
50 to <75	Bimonthly	Three quarters	Semiannually
75 to 100	Monthly	Quarterly	Semiannually

2. Pumps and valves that are shared among two or more batch process units that are subject to 40 CFR Part 60 Subpart VVa may be monitored at the frequencies specified in 40 CFR §60.482-1a (f)(1), provided the operating time of all such process units is considered.
3. The monitoring frequencies specified in 40 CFR §60.482-1a (f)(1) are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. The permittee may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in 40 CFR §§60.482-1a (f)(3)(i) through (iv).
- i. When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.
- ii. When monitoring is conducted semiannually (i.e. , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.
- iii. When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.
- iv. When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.
- g. If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to 40 CFR Part 60 Subpart VVa, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to 40 CFR Part 60 Subpart VVa, the storage vessel is assigned to any process unit subject to 40 CFR Part 60 Subpart VV. If the predominant use of the storage vessel varies from year to year, then the permittee must estimate the predominant use initially and reassess every 3 years. The permittee must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

[45CSR16, 40 CFR §60.482-1a, 45CSR13: R13-2334, 8.1.6.]

Standards: Pumps in Light Liquid Service

- 8.1.11. a. 1. Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR §60.485a (b), except as provided in 40 CFR §§60.482-1a (c) and (f) and 40 CFR §§60.482-2a (d), (e), and (f). 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 40 CFR §60.482-1a (c) and 40 CFR §§60.482-2a (d), (e), and (f).
2. Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in 40 CFR §60.482-1a (f).
- b. 1. The instrument reading that defines a leak is specified in 40 CFR §§60.482-2a (b)(1)(i) and (ii).
- i. 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
- ii. 2,000 ppm or greater for all other pumps.
2. If there are indications of liquids dripping from the pump seal, the permittee shall follow the procedure specified in either 40 CFR §60.482-2a (b)(2)(i) or (ii). This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in 40 CFR § 60.482-2a (b)(1)(i) or (ii), whichever is applicable.
- i. Monitor the pump within 5 days as specified in 40 CFR § 60.485a (b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in 40 CFR § 60.482-2a (b)(1)(i) or (ii), whichever is applicable. The leak shall be repaired using the procedures in 40 CFR § 60.482-2a (c).
- ii. Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in 40 CFR § 60.482-2a (c) or by eliminating the visual indications of liquids dripping.
- c. 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in 40 CFR §§ 60.482-2a (c)(2)(i) and (ii), where practicable.
- i. Tightening the packing gland nuts;
- ii. Ensuring that the seal flush is operating at design pressure and temperature
- d. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of 40 CFR § 60.482-2a (a), provided the requirements specified in 40 CFR §§ 60.482-2a (d)(1) through (6) are met.
1. Each dual mechanical seal system is:

- i. Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or
 - ii. 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 40 CFR § 60.482-10a; or
 - iii. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
2. The barrier fluid system is in heavy liquid service or is not in VOC service.
3. Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.
4.
 - i. Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.
 - ii. If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the permittee shall follow the procedure specified in either 40 C.F.R. § 60.482-2a (d) (4) (ii) (A) or (B) prior to the next required inspection.
 - A. Monitor the pump within 5 days as specified in 40 CFR § 60.485a (b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
 - B. Designate the visual indications of liquids dripping as a leak.
5.
 - i. Each sensor as described in 40 CFR § 60.482-2a (d)(3) is checked daily or is equipped with an audible alarm.
 - ii. 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.
 - iii. If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in 40 CFR § 60.482-2a (d)(5)(ii), a leak is detected.
6.
 - i. When a leak is detected pursuant to 40 CFR § 60.482-2a (d)(4)(ii)(A), it shall be repaired as specified in 40 CFR § 60.482-2a (c).
 - ii. A leak detected pursuant to 40 CFR § 60.482-2a (d)(5)(iii) shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.
 - iii. A designated leak pursuant to 40 CFR § 60.482-2a (d)(4)(ii)(B) shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.
- e. Any pump that is designated, as described in 40 CFR §§ 60.486a (e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR §§ 60.482-2a (a), (c), and (d) if the pump:

1. Has no externally actuated shaft penetrating the pump housing;
 2. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 C.F.R. § 60.485a (c); and
 3. Is tested for compliance with 40 CFR § 60.482-2a (e)(2) initially upon designation, annually, and at other times requested by the Administrator.
- f. 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 or to a fuel gas system or to a control device that complies with the requirements of 40 CFR § 60.482-10a, it is exempt from 40 CFR §§ 60.482-2a (a) through (e).
- g. Any pump that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 40 CFR §§ 60.482-2a (a) and (d)(4) through (6) if:
1. The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 C.F.R. § 60.482-2a (a); and
 2. The owner or operator of the pump 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 repair of the equipment according to the procedures in 40 CFR § 60.482-2a (c) if a leak is detected.
- h. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of 40 CFR §§ 60.482-2a (a)(2) and (d)(4), and the daily requirements of 40 CFR § 60.482-2a (d)(5), provided that each pump is visually inspected as often as practicable and at least monthly.

[45CSR16, 40 CFR § 60.482-2a, 45CSR13, R13-2334, 8.1.6.]

Standards: Compressors

- 8.1.12. a. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR §§ 60.482-3a (h), (i), and (j).
- b. Each compressor seal system as required in 40 CFR § 60.482-3a (a) shall be:
1. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
 2. Equipped with a barrier fluid system 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 40 CFR § 60.482-10a; or

3. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. Each barrier fluid system as described in 40 CFR § 60.482-3a (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.
- e.
 1. Each sensor as required in 40 CFR § 60.482-3a (d) shall be checked daily or shall be equipped with an audible alarm.
 2. The permittee shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.
- f. If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under 40 CFR § 60.482-3a (e)(2), a leak is detected.
- g.
 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
 2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- h. A compressor is exempt from the requirements of 40 CFR §§ 60.482-3a (a) and (b), if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of 40 CFR § 60.482-10a, except as provided in paragraph (i) of this section.
- i. Any compressor that is designated, as described in 40 CFR §§ 60.486a (e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR §§ 60.482-3a (a) through (h) if the compressor:
 1. Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in 40 CFR § 60.485a (c); and
 2. Is tested for compliance with 40 CFR § 60.482-3a (i)(1) initially upon designation, annually, and at other times requested by the Administrator.
- j. Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of 40 CFR § 60.14 or 40 CFR § 60.15 is exempt from 40 CFR §§ 60.482-3a (a) through (e) and (h), provided the permittee demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §§ 60.482-3a (a) through (e) and (h).

[45CSR16, 40 CFR § 60.482-3a, 45CSR13: R13-2334, 8.1.6]

Standards: Pressure relief devices in gas/vapor service.

- 8.1.13. a. Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR § 60.485a (c).
- b. 1. After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR § 60.482-9a.
2. No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR § 60.485a (c).
- c. 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 40 CFR § 60.482-10a is exempted from the requirements of 40 CFR §§ 60.482-4a (a) and (b).
- d. 1. Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of 40 CFR §§ 60.482-4a (a) and (b), provided the permittee complies with the requirements in 40 CFR § 60.482-4a (d)(2).
2. After each pressure release, a new rupture disk shall be installed 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 40 CFR § 60.482-9a.

[45CSR16, 40 CFR § 60.482-4a, 45CSR13: R13-2334, 8.1.6.]

Standards: Sampling connection systems.

- 8.1.14. a. Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR § 60.482-5a (c).
- b. Each closed-purge, closed-loop, or closed-vent system as required in 40 CFR § 60.482-5a (a) shall comply with the requirements specified in 40 CFR §§ 60.482-5a (b)(1) through (4).
1. Gases displaced during filling of the sample container are not required to be collected or captured.
2. Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.
3. Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.
4. Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either 40 C.F.R. §§ 60.482-5a (b) (4) (i), (ii), (iii), or (iv).

- i. Return the purged process fluid directly to the process line.
- ii. Collect and recycle the purged process fluid to a process.
- iii. Capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR § 60.482-10a.
- iv. Collect, store, and transport the purged process fluid to any of the following systems or facilities:
 - A. A waste management unit as defined in 40 CFR § 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR Part 63 Subpart G, applicable to Group 1 wastewater streams;
 - B. A treatment, storage, or disposal facility subject to regulation under 40 CFR Part 262, 264, 265, or 266;
 - C. A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR Part 261;
 - D. A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR § 61.348 (a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR. § 61.343 through 40 CFR § 61.347; or
 - E. A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR Part 279 Subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR Part 261.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of 40 CFR §§ 60.482-5a (a) and (b).

[45CSR16, 40 CFR § 60.482-5a, 45CSR13: R13-2334, 8.1.6.]

Standards: Open-ended valves or lines.

- 8.1.15. a.
 - 1. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR §§ 60.482-6a (d) and (e).
 - 2. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

- c. 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 comply with 40 CFR § 60.482-6a (a) at all other times.
- d. 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 §§ 60.482-6a (a), (b), and (c).
- e. 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 40 CFR §§ 60.482-6a (a) through (c) are exempt from the requirements of 40 CFR §§ 60.482-6a (a) through (c).

[45CSR16, 40 CFR § 60.482-6a, 45CSR13, R13-2334, 8.1.6.]

Standards: Valves in gas/vapor service and in light liquid service.

- 8.1.16. a. 1. Each valve shall be monitored monthly to detect leaks by the methods specified in 40 CFR § 60.485a (b) and shall comply with 40 CFR §§ 60.482-7a (b) through (e), except as provided in 40 CFR §§ 60.482-7a (f), (g), and (h), 40 CFR §§ 60.482-1a (c) and (f), and 40 CFR §§ 60.483-1a and 60.483-2a.
2. A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to 40 CFR § 60.482-7a (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in 40 CFR §§ 60.482-7a (f), (g), and (h), 40 CFR § 60.482-1a (c), and 40 CFR §§ 60.483-1a and 60.483-2a.
- i. Monitor the valve as in 40 CFR § 60.482-7a (a)(1). The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.
 - ii. If the existing valves in the process unit are monitored in accordance with 40 CFR § 60.483-1a or 40 CFR § 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in 40 C.F.R. § 60.483-2a (b) (5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.
- b. If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- c. 1. i. Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.
 - ii. As an alternative to monitoring all of the valves in the first month of a quarter, the permittee may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The permittee must keep records of the valves assigned to each subgroup.
2. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

- d.
 - 1. When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR § 60.482-9a.
 - 2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- e. First attempts at repair include, but are not limited to, the following best practices where practicable:
 - 1. Tightening of bonnet bolts;
 - 2. Replacement of bonnet bolts;
 - 3. Tightening of packing gland nuts;
 - 4. Injection of lubricant into lubricated packing.
- f. Any valve that is designated, as described in 40 CFR § 60.486a (e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR § 60.482-7a (a) if the valve:
 - 1. Has no external actuating mechanism in contact with the process fluid,
 - 2. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR § 60.485a (c), and
 - 3. Is tested for compliance with 40 CFR § 60.482-7a (f)(2) initially upon designation, annually, and at other times requested by the Administrator.
- g. Any valve that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 40 CFR § 60.482-7a (a) if:
 - 1. The permittee of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR § 60.482-7a (a), and
 - 2. The permittee of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.
- h. Any valve that is designated, as described in 40 CFR § 60.486a (f)(2), as a difficult-to-monitor valve is exempt from the requirements of 40 CFR § 60.482-7a (a) if:
 - 1. The permittee of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
 - 2. The process unit within which the valve is located either:
 - i. Becomes an affected facility through 40 CFR § 60.14 or 40 CFR § 60.15 and was constructed on or before January 5, 1981; or

- ii. Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the permittee.
- 3. The permittee of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[45CSR16, 40 CFR § 60.482-7a, 45CSR13: R13-2334, 8.1.6.]

Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

- 8.1.17. a. If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the permittee shall follow either one of the following procedures:
 - 1. The permittee shall monitor the equipment within 5 days by the method specified in 40 CFR § 60.485a (b) and shall comply with the requirements of 40 CFR §§ 60.482-8a (b) through (d).
 - 2. The permittee shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c.
 - 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
 - 2. The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- d. First attempts at repair include, but are not limited to, the best practices described under 40 CFR §§ 60.482-2a (c)(2) and 60.482-7a (e).

[45CSR16, 40 CFR § 60.482-8a, 45CSR13: R13-2334, 8.1.6.]

Standards: Delay of repair.

- 8.1.18. a. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment 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.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves and connectors will be allowed if:
 - 1. 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

2. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR § 60.482-10a.
- d. Delay of repair for pumps will be allowed if:
 1. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
 2. Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.
- e. 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.
- f. When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

[45CSR16, 40 CFR § 60.482-9a, 45CSR13: R13-2334, 8.1.6.]

Standards: Closed vent systems and control devices.

- 8.1.19. a. Owners or operators of closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VVa shall comply with the provisions of 40 CFR § 60.482-10a.
- b. Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.
 - c. Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816°C.
 - d. Flares used to comply with 40 CFR Part 60 Subpart VVa shall comply with the requirements of 40 CFR § 60.18.
 - e. Owners or operators of control devices used to comply with the provisions of 40 CFR Part 60 Subpart VVa shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.
 - f. Except as provided in 40 CFR §§ 60.482-10a (i) through (k), each closed vent system shall be inspected according to the procedures and schedule specified in 40 CFR §§ 60.482-10a (f) (1) and (2).
 1. If the vapor collection system or closed vent system is constructed of hard-piping, the permittee shall comply with the requirements specified in 40 CFR §§ 60.482-10a (f)(1)(i) and (ii):
 - i. Conduct an initial inspection according to the procedures in 40 CFR § 60.485a (b); and

- ii. Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.
- 2. If the vapor collection system or closed vent system is constructed of ductwork, the permittee shall:
 - i. Conduct an initial inspection according to the procedures in 40 CFR § 60.485a (b); and
 - ii. Conduct annual inspections according to the procedures in 40 CFR § 60.485a (b).
- g. Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in 40 CFR § 60.482-10a (h).
 - 1. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
 - 2. Repair shall be completed no later than 15 calendar days after the leak is detected.
- h. Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the permittee determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.
- i. If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2).
- j. Any parts of the closed vent system that are designated, as described in 40 CFR § 60.482-10a (l)(1), as unsafe to inspect are exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR §§ 60.482-10a (j)(1) and (2):
 - 1. The permittee 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 40 CFR § 60.482-10a (f)(1)(i) or (f)(2); and
 - 2. The permittee has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.
- k. Any parts of the closed vent system that are designated, as described in 40 CFR § 60.482-10a (l)(2), as difficult to inspect are exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR §§ 60.482-10a (k)(1) through (3):
 - 1. The permittee determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and
 - 2. The process unit within which the closed vent system is located becomes an affected facility through 40 CFR § 60.14 or 60.15, or the permittee designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and
 - 3. The permittee has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

- l. The permittee shall record the information specified in 40 CFR §§ 60.482-10a (l)(1) through (5).
 1. Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.
 2. Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.
 3. For each inspection during which a leak is detected, a record of the information specified in 40 CFR § 60.486a (c).
 4. For each inspection conducted in accordance with 40 CFR § 60.485a (b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
 5. For each visual inspection conducted in accordance with 40 CFR § 60.482-10a (f)(1)(ii) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- m. Closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VVa shall be operated at all times when emissions may be vented to them.

[45CSR16, 40 CFR § 60.482-10a, 45CSR13: R13-2334, 8.1.6.]

- 8.1.20. a. The owner or operator shall 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 owner or operator is required to monitor only those connectors involved in the process change.
- b. Except as allowed in 40 CFR § 60.482-1a (c), 40 CFR § 60.482-10a, or as specified in 40 CFR § 60.482-11a (e), the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in 40 CFR §§ 60.482-11a (a) and (b) (3).
 1. The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, 40 CFR § 60.485a (c).
 2. If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.
 3. The owner or operator shall perform monitoring, subsequent to the initial monitoring required in 40 CFR § 60.482-11a (a), as specified in 40 CFR §§ 60.482-11a (b)(3)(i) through (iii), and shall comply with the requirements of 40 CFR §§ 60.482-11a (b)(3)(iv) and (v). The required period in which monitoring must be conducted shall be determined from 40 CFR §§ 60.482-11a (b)(3)(i) through (iii) using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in 40 CFR § 60.482-11a (c).

- i. If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).
- ii. If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
- iii. If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in 40 CFR § 60.482-11a (b)(3)(iii)(A) and either 40 CFR § 60.482-11a (b)(3)(iii)(B) or (b)(3)(iii)(C), as appropriate.
 - A. An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
 - B. If the percent of leaking connectors calculated from the monitoring results in 40 CFR § 60.482-11a (b)(3)(iii)(A) is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to 40 CFR § 60.482-11a (b)(3), based on the percent of leaking connectors within the total monitored connectors.
 - C. If the percent of leaking connectors calculated from the monitoring results in 40 CFR § 60.482-11a (b)(3)(iii)(A) is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.
- iv. If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
- v. The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.
- c. For use in determining the monitoring frequency, as specified in 40 CFR §§ 60.482-11a (a) and (b)(3), the percent leaking connectors as used in 40 CFR §§ 60.482-11a (a) and (b)(3) shall be calculated by using the following equation:

$$\%C_L = C_L / C_t \times 100$$

Where:

- $\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in 40 CFR §§ 60.482-11a (a) and (b)(3)(i) through (iii).
- C_L = Number of connectors measured at 500 ppm or greater, by the method specified in 40 CFR § 60.485a (b).
- C_t = Total number of monitored connectors in the process unit or affected facility.

- d. When a leak is detected pursuant to 40 CFR §§ 60.482-11a (a) and (b), it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.
- e. Any connector that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor connector is exempt from the requirements of 40 CFR §§ 60.482-11a (a) and (b) if:
 - 1. The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR §§ 60.482-11a (a) and (b); and
 - 2. The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in 40 CFR § 60.482-11a (d) if a leak is detected.
- f. *Inaccessible, ceramic, or ceramic-lined connectors.*
 - 1. 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 (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of 40 CFR §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in 40 CFR §§ 60.482-11a (f)(1)(i) through (vi), as applicable:
 - i. Buried;
 - ii. Insulated in a manner that prevents access to the connector by a monitor probe;
 - iii. Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
 - iv. 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;
 - v. Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
 - vi. 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.
 - 2. If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

- g. Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

[45CSR16, 40 CFR § 60.482-11a, 45CSR13: R13-2334, 8.1.6.]

- 8.1.21. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in 40 CFR Part 60 Subpart VVa.
- b. Determination of equivalence to the equipment, design, and operational requirements of 40 CFR Part 60 Subpart VVa will be evaluated by the following guidelines:
 - 1. Each permittee applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.
 - 2. The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.
 - 3. The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.
- c. Determination of equivalence to the required work practices in 40 CFR Part 60 Subpart VVa will be evaluated by the following guidelines:
 - 1. Each permittee applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.
 - 2. For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.
 - 3. For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.
 - 4. Each permittee applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.
 - 5. The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in 40 CFR § 60.484a (c)(4).
 - 6. The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

- d. The permittee may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.
- e.
 - 1. After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.
 - 2. After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.
 - 3. Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111 (h) (1) of the CAA.
- f.
 - 1. Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of 40 CFR Part 60 Subpart VVa.
 - 2. The Administrator will make an equivalence determination according to the provisions of 40 CFR §§ 60.484a (b), (c), (d), and (e).

[45CSR16, 40 CFR § 60.484a, 45CSR13: R13-2334, 8.1.6.]

8.2. Monitoring Requirements

- 8.2.1. **Reporting, Recording, Tracking, Repairing and Re-monitoring Leaks of Valves and Pumps.** The permittee shall record, track, repair and re-monitor all leaks in excess of the internal leak definitions.
[45CSR13: Permit R13-2334, 8.2.1., 45CSR§30-12.7]

8.2.2. **LDAR Monitoring Frequency**

- i. Pumps. The permittee shall monitor pumps on a monthly basis.
- ii. Valves. The permittee shall monitor valves -- other than difficult to monitor or unsafe to monitor valves -- on a quarterly basis.

[45CSR13: Permit R13-2334, 8.2.2., 45CSR§30-12.7]

8.2.3. **Calibration/Calibration Drift Assessment**

- i. Calibration. The permittee shall conduct all calibrations of LDAR monitoring equipment using methane as the calibration gas, in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21.
- ii. Calibration Drift Assessment. The permittee shall conduct calibration drift assessments of LDAR monitoring equipment at the end of each monitoring shift, at a minimum. The permittee shall conduct the calibration drift assessment using, at a minimum, a 500 ppm calibration gas. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous

calibration, the permittee shall re-monitor all valves that were monitored since the last calibration that had a reading greater than 100 ppm and shall re-monitor all pumps that were monitored since the last calibration that had a reading greater than 500 ppm.

[45CSR13: Permit R13-2334, 8.2.3., 45CSR§30-12.7]

- 8.2.4. **LDAR Audits.** The permittee shall implement at the facility the Refinery audits set forth in the following paragraphs to ensure compliance with all applicable LDAR requirements. The LDAR audits shall include, but not be limited to, comparative monitoring, records review, tagging, data management, and observation of the LDAR technicians' calibration and monitoring techniques.
- i. **Third-Party Audits.** The permittee shall retain a contractor(s) to perform a third-party audit of the refinery's LDAR program at least once every four years.
 - ii. **Internal Audits.** The permittee shall conduct internal audits of the LDAR program. An internal audit of the refinery shall be held every four years.
 - iii. To ensure that an audit at the refinery occurs every two years, third party and internal audits shall be separated by two years.
 - iv. **Alternative.** As an alternative to the internal audit, the permittee may elect to retain third-parties to undertake the internal audit, provided that an audit of the facility occurs every two (2) years.

[45CSR13: Permit R13-2334, 8.2.4., 45CSR§30-12.7]

- 8.2.5. If the results of any of the audits conducted at the facility identify any areas of non-compliance, the permittee shall implement, as soon as practicable, all steps necessary to correct the area(s) of noncompliance, and to prevent, to the extent practicable, a recurrence of the cause of the non-compliance. The permittee shall retain the audit reports generated during the audits and shall maintain a written record of the corrective actions taken at the facility in response to any deficiencies identified in any audits.

[45CSR13: Permit R13-2334, 8.2.4., 45CSR§30-12.7]

8.3. Testing Requirements

- 8.3.1. For affected facilities subject to the standards in 40 CFR §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a, the permit shall determine compliance with the standards according to the test methods and procedures provided in §60.485a.
- a. In conducting the performance tests required in 40 CFR § 60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in 40 CFR § 60.8 (b).
 - b. The permittee shall determine compliance with the standards in 40 CFR §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:
 - 1. Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of 40 CFR Part 60 Appendix A-7. The following calibration gases shall be used:

- i. Zero air (less than 10 ppm of hydrocarbon in air); and
 - ii. A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the permittee need not calibrate the scales that will not be used during that day's monitoring.
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 40 CFR Part 60 Appendix A-7, 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) (7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration 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 initial calibration value, 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 initial calibration value, 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.
- c. The permittee shall determine compliance with the no-detectable-emission standards in 40 CFR §§ 60.482-2a (e), 60.482-3a (i), 60.482-4a, 60.482-7a (f), and 60.482-10a (e) as follows:
 1. The requirements of 40 CFR § 60.485a (b) shall apply.
 2. Method 21 of 40 CFR Part 60 Appendix A-7 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.
 - d. The permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:
 1. Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see 40 CFR § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
 2. Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

3. Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, 40 CFR §§ 60.485a (d)(1) and (2) shall be used to resolve the disagreement.
- e. The permittee shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:
 1. The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see 40 CFR § 60.17) shall be used to determine the vapor pressures.
 2. The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.
 3. The fluid is a liquid at operating conditions.
- f. Samples used in conjunction with 40 CFR §§ 60.485a (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.
- g. The permittee shall determine compliance with the standards of flares as follows:
 1. Method 22 of 40 CFR Part 60 Appendix A-7 shall be used to determine visible emissions.
 2. A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.
 3. The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

- V_{max} = Maximum permitted velocity, m/sec (ft/sec).
 H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).
 K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).
 K_2 = 0.7084 m⁴/(MJ-sec) (metric units) = 0.087 ft⁴/(Btu-sec) (English units).

4. The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

- K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).
 C_i = Concentration of sample component “i,” ppm
 H_i = net heat of combustion of sample component “i” at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

5. Method 18 of 40 CFR Part 60 Appendix A-6 or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see 40 C.F.R. § 60.17) shall be used to determine the concentration of sample component “i.”
 6. ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see 40 CFR § 60.17) shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.
 7. Method 2, 2A, 2C, or 2D of 40 CFR Part 60 Appendix A-7, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.
- h. The permittee shall determine compliance with 40 CFR § 60.483-1a or 40 CFR § 60.483-2a as follows:
1. The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L/V_T) \times 100$$

Where:

$\%V_L$	=	Percent leaking valves.
V_L	=	Number of valves found leaking.
V_T	=	The sum of the total number of valves monitored.

2. The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
3. The number of valves leaking shall include valves for which repair has been delayed.
4. Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
5. If the process unit has been subdivided in accordance with 40 CFR § 60.482-7a (c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
6. The total number of valves monitored does not include a valve monitored to verify repair.

[45CSR16, 40 CFR § 60.485a, 45CSR13: R13-2334, 8.3.1.]

8.4. Recordkeeping Requirements

- 8.4.1. **Adding New Valves and Pumps.** The permittee shall establish a tracking program for maintenance records (e.g., a Management of Change program) to ensure that valves and pumps added to the facility during maintenance and construction are integrated into the LDAR program.

[45CSR13: Permit R13-2334, 8.4.1., 45CSR§30-12.7]

8.4.2. When a leak is detected, the following requirements apply:

- i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- ii. The identification on a valve may be removed after it has been monitored for 2 successive months and no leak has been detected during those 2 months.
- iii. The identification on equipment, except on a valve, may be removed after it has been repaired.
[40 CFR § 60.486a(b), 45CSR13: Permit R13-2334, 8.4.2., 45CSR§30-12.7]

8.4.3. When a leak has been detected, the following information shall be recorded in a log and 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 10,000” if the maximum instrument reading measured after each repair attempt is equal to or greater than 10,000 ppm.
- v. “Repair delayed” and 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.

[40 CFR § 60.486a(c), 45CSR13: Permit R13-2334, 8.4.3., 45CSR§30-12.7]

8.4.4. The following information shall be recorded in a log that is kept in a readily accessible location:

- i. A list of identification numbers.
- ii. A list of identification numbers for equipment that are designated for no detectable emissions. This list shall be signed by the owner or operator.
- iii. A list of equipment identification numbers for pressure relief valves.
- iv. The dates of each compliance test.
- v. The background level measured during each compliance test.

- vi. The maximum instrument reading measured at the equipment during each compliance test.
- vii. A list of identification numbers for equipment in vacuum service.
- viii. A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr, a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

[40 CFR § 60.486a(e), 45CSR13: Permit R13-2334, 8.4.3., 45CSR§30-12.7]

- ix. For all valves and pumps designated as unsafe-to-monitor or difficult-to-monitor:
 - a. A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.
 - b. 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.

[40 CFR § 60.486a(f), 45CSR13: Permit R13-2334, 8.4.4.(xi.), 45CSR§30-12.7]

- 8.4.5. a.
 - 1. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall comply with the recordkeeping requirements of 40 CFR § 60.486a.
 - 2. The permittee of more than one affected facility subject to the provisions of 40 CFR Part 60 Subpart VVa may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
 - 3. The permittee shall record the information specified in 40 CFR §§ 60.486a (a)(3)(i) through (v) for each monitoring event required by 40 CFR §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.
 - i. Monitoring instrument identification.
 - ii. Operator identification.
 - iii. Equipment identification.
 - iv. Date of monitoring.
 - v. Instrument reading.
- b. When each leak is detected as specified in 40 CFR §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:
 - 1. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

2. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7a (c) and no leak has been detected during those 2 months.
 3. The identification on a connector may be removed after it has been monitored as specified in § 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
 4. The identification on equipment, except on a valve or connector, may be removed after it has been repaired.
- c. When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall 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, except when indications of liquids dripping from a pump are designated as a leak.
 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. Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonreparable, except when a pump is repaired by eliminating indications of liquids dripping.
 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 permittee (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.
- d. The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10a shall be recorded and kept in a readily accessible location:
1. Detailed schematics, design specifications, and piping and instrumentation diagrams.
 2. The dates and descriptions of any changes in the design specifications.
 3. A description of the parameter or parameters monitored, as required in § 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

4. Periods when the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
5. Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.
- e. The following information pertaining to all equipment subject to the requirements in §§ 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:
 1. A list of identification numbers for equipment subject to the requirements of 40 CFR Part 60 Subpart VVa.
 2.
 - i. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR §§ 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
 - ii. The designation of equipment as subject to the requirements of § 60.482-2a(e), § 60.482-3a(i), or § 60.482-7a(f) shall be signed by the permittee. Alternatively, the permittee may establish a mechanism with their permitting authority that satisfies this requirement.
 3. A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4a.
 4.
 - i. The dates of each compliance test as required in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
 - ii. The background level measured during each compliance test.
 - iii. The maximum instrument reading measured at the equipment during each compliance test.
 5. A list of identification numbers for equipment in vacuum service.
 6. A list of identification numbers for equipment that the permittee designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
 7. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
 8. Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and § 60.485a(b).
 - i. Date of calibration and initials of operator performing the calibration.
 - ii. Calibration gas cylinder identification, certification date, and certified concentration.
 - iii. Instrument scale(s) used.

- iv. 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 of this part.
 - v. Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
 - vi. If the permittee makes their own calibration gas, a description of the procedure used.
- 9. The connector monitoring schedule for each process unit as specified in § 60.482-11a (b)(3) (v).
- 10. Records of each release from a pressure relief device subject to § 60.482-4a.
- f. The following information pertaining to all valves subject to the requirements of 40 CFR §§ 60.482-7a (g) and (h), all pumps subject to the requirements of 40 CFR § 60.482-2a (g), and all connectors subject to the requirements of 40 CFR § 60.482-11a (e) shall be recorded in a log that is kept in a readily accessible location:
 - 1. 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.
 - 2. 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.
- g. The following information shall be recorded for valves complying with 40 CFR § 60.483-2a:
 - 1. A schedule of monitoring.
 - 2. The percent of valves found leaking during each monitoring period.
- h. The following information shall be recorded in a log that is kept in a readily accessible location:
 - 1. Design criterion required in 40 CFR §§ 60.482-2a (d)(5) and 60.482-3a (e)(2) and explanation of the design criterion; and
 - 2. Any changes to this criterion and the reasons for the changes.
- i. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR § 60.480a (d):
 - 1. An analysis demonstrating the design capacity of the affected facility,
 - 2. A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
 - 3. An analysis demonstrating that equipment is not in VOC service.

- j. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.
- k. The provisions of 40 CFR §§ 60.7(b) and (d) do not apply to affected facilities subject to 40 CFR Part 40 Subpart VVa.

[45CSR16, 40 CFR § 60.486a, 45CSR13: R13-2334, 8.4.5.]

8.5. Reporting Requirements

8.5.1. Electronic Monitoring, Storing, and Reporting of LDAR Data

- i. Electronic Storing and Reporting of LDAR Data. The facility will maintain an electronic database (e.g., EXCEL spreadsheet) for storing and reporting LDAR data. The electronic database shall include data identifying the date and time of the monitored event, and the operator and instrument used in the monitored event.
- ii. Electronic Data Collection During LDAR Monitoring and Transfer Thereafter. The permittee shall use data loggers and/or electronic data collection devices during all LDAR monitoring. The permittee, or its designated contractor, shall use its/their best efforts to transfer, by the end of the next business day, electronic data from electronic data logging devices to the electronic database listed above. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp. The permittee may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken), and shall record, at a minimum, the identification of the technician undertaking the monitoring, the date, and the identification of the monitoring equipment. The permittee shall use its best efforts to transfer any manually recorded monitoring data to the electronic database within seven days of monitoring.

[45CSR13: Permit R13-2334, 8.5.1., 45CSR§30-12.7]

- 8.5.2. **QA/QC of LDAR Data** - The permittee shall ensure that monitoring data provided to the permittee by its contractors is reviewed for QA/QC before the contractor submits the data to the permittee. At least once per calendar quarter, the permittee shall perform QA/QC of the contractor's monitoring data which shall include, but not be limited to, number of components monitored per technician, time between monitoring events, and abnormal data patterns.

[45CSR13: Permit R13-2334, 8.5.2., 45CSR§30-12.7]

- 8.5.3. The permittee shall submit semiannual reports to the Administrator beginning six months after the initial startup date. All semiannual reports shall include the following information:

- i. Process unit identification.
- ii. For each month during the semiannual reporting period,
 - a. Number of valves for which leaks were detected.
 - b. Number of valves for which leaks were not repaired.
 - c. Number of pumps for which leaks were detected.

- d. Number of pumps for which leaks were not repaired.
 - e. Number of compressors for which leaks were detected.
 - f. Number of compressors for which leaks were not repaired.
 - g. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - iv. Revisions to items reported in initial report if changes have occurred since the initial report or subsequent revisions to the initial report.

[40 CFR § 60.487a(c), 45CSR13: Permit R13-2334, 8.5.3., 45CSR§30-12.7]

- 8.5.4. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.
- b. The initial semiannual report to the Administrator shall include the following information:
 - 1. Process unit identification.
 - 2. Number of valves subject to the requirements of 40 CFR § 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of 40 CFR § 60.482-7a (f).
 - 3. Number of pumps subject to the requirements of 40 CFR § 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of 40 CFR § 60.482-2a (e) and those pumps complying with 40 CFR § 60.482-2a (f).
 - 4. Number of compressors subject to the requirements of 40 CFR § 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of 40 CFR § 60.482-3a (i) and those compressors complying with 40 CFR § 60.482-3a (h).
 - 5. Number of connectors subject to the requirements of 40 CFR § 60.482-11a.
- c. All semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR § 60.486a:
 - 1. Process unit identification.
 - 2. For each month during the semiannual reporting period,
 - i. Number of valves for which leaks were detected as described in 40 CFR § 60.482-7a (b) or § 60.483-2a,
 - ii. Number of valves for which leaks were not repaired as required in 40 CFR § 60.482-7a (d)(1),

- iii. Number of pumps for which leaks were detected as described in 40 CFR § 60.482-2a (b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
 - iv. Number of pumps for which leaks were not repaired as required in 40 CFR §§ 60.482-2a(c)(1) and (d)(6),
 - v. Number of compressors for which leaks were detected as described in 40 CFR § 60.482-3a (f),
 - vi. Number of compressors for which leaks were not repaired as required in 40 CFR § 60.482-3a (g) (1),
 - vii. Number of connectors for which leaks were detected as described in 40 CFR § 60.482-11a (b)
 - viii. Number of connectors for which leaks were not repaired as required in 40 CFR § 60.482-11a (d), and
 - ix. [Reserved]
 - x. [Reserved]
 - xi. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- 3. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - 4. Revisions to items reported according to 40 CFR § 60.487a (b) if changes have occurred since the initial report or subsequent revisions to the initial report.
- d. The permittee electing to comply with the provisions of 40 CFR §§ 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.
 - e. The permittee shall report the results of all performance tests in accordance with 40 CFR § 60.8 of the General Provisions. The provisions of 40 CFR § 60.8 (d) do not apply to affected facilities subject to the provisions of 40 CFR Part 60 Subpart VVa except that the permittee must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.
 - f. The requirements of 40 CFR §§ 60.487a (a) through (c) remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of 40 CFR §§ 60.487a (a) through (c), provided that they comply with the requirements established by the state.
- [45CSR13: R13-2334, 8.5.4., 45CSR16, 40 CFR § 60.487a]**

8.6. Compliance Plan

- 8.6.1. None.

9.0 Equipment Leaks Requirements [VOC Emissions from Petroleum Refinery Wastewater Systems - 40 CFR Part 60 Subpart QQQ]

9.1. Limitations and Standards

- 9.1.1. a. Each owner or operator subject to the provisions of this subpart shall comply with the requirements of 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.
- b. Compliance with 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.696.
- ~~c.~~ 1. Stormwater sewer systems are not subject to the requirements of this subpart.
2. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.
3. Non-contact cooling water systems are not subject to the requirements of this subpart.
4. An owner or operator shall demonstrate compliance with the exclusions in paragraphs c.1., 2., and 3. of this section as provided in 40 CFR § 60.697 (h), (i), and (j).

[40 CFR § 60.692-1(a), (b), and (d), 45CSR16, 45CSR13: Permit R13-2334, 9.1.1.]

9.1.2. Individual drain systems.

- a. 1. Each drain shall be equipped with water seal controls.
2. Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
3. Each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.
4. Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in 40 CFR § 60.692-6.
- b. 1. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
2. 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.
3. Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

4. If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in 40 CFR § 60.692-6.
- c.
 1. 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.
 2. The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.
 3. Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in 40 CFR § 60.692-6.
- d. Except as provided in paragraph e. of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987, shall be exempt from the provisions of this section.
- e. Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

[40 CFR § 60.692-2, 45CSR16, 45CSR13: Permit R13-2334, 9.1.2.]

9.1.3. Oil-water separators.

- a. Each oil-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 following specifications, except as provided in paragraph c. of this section or in 40 CFR § 60.693-2.
 1. The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
 2. The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
 3. If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
 4. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.
 5. When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.
- b. Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements

in paragraph a. of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of 40 CFR § 60.692-5.

- c. Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in 40 CFR §§ 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, Subparts K, Ka, or Kb are not subject to the requirements of this section.
- d. Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of 40 CFR Part 60, Subpart QQQ. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph a. of this section.
- e. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph a. of this section, and not paragraph b. of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

[40 CFR § 60.692-3 (a), (b), (d), (e), and (f), 45CSR16, 45CSR13: Permit R13-2334, 9.1.3.]

9.1.4. Alternative standards for oil-water separators.

- a. An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.
 - 1. Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.
 - i. The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.
 - A. A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.
 - B. The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.
 - C. The total gap area between the primary seal and the separator wall shall not exceed 67 cm²/m (3.2 in.²/ft) of separator wall perimeter.
 - ii. The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.
 - A. The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

- B. The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm²/m (0.32 in.²/ft) of separator wall perimeter.
 - iii. The maximum gap width and total gap area shall be determined by the methods and procedures specified in 40 CFR § 60.696(d).
 - A. Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.
 - B. Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.
 - iv. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs a.1.i. and ii. of this section.
- 2. Except as provided in paragraph a.4. of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.
- 3. The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).
- 4. The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.
- 5.
 - i. Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.
 - ii. When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.
- b. An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph a. of this section.
- c. For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of 40 CFR § 60.692-3(a) shall be installed.
- d. Except as provided in paragraph c. of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of 40 CFR §§ 60.692-3 or 60.694 applicable to the same facilities.

[40 CFR § 60.693-2, 45CSR 16, 45CSR13: Permit R13-2334, 9.1.4.]

9.1.5. Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of 40 CFR §§ 60.692-2 and 60.692-3.

[40 CFR § 60.692-4, 45CSR16, 45CSR13: Permit R13-2334, 9.1.5.]

9.1.6. Closed vent systems and control devices.

- a. Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.
- b. Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.
- c.
 1. Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR § 60.696.
 2. Closed vent systems shall be purged to direct vapor to the control device.
 3. A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.
 4. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.
 5. When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR § 60.692-6.

[40 CFR §§ 60.692-5(b), (d), and (e), 45CSR16, 45CSR13: Permit R13-2334, 9.1.6.]

9.1.7. Delay of repair.

- a. 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.
- b. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

[40 CFR § 60.692-6, 45CSR16, 45CSR13: Permit R13-2334, 9.1.7.]

9.2. Monitoring Requirements

- 9.2.1. Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

- a. Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

[40 CFR § 60.695(a)(3)(ii), 45CSR16, 45CSR13: Permit R13-2334, 9.2.1.]

9.3. Testing Requirements

- 9.3.1. Before using any equipment installed in compliance with the requirements of 40 CFR § 60.692-2, § 60.692-3, § 60.692-4, § 60.692-5, or § 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

[40 CFR § 60.696(a), 45CSR16, 45CSR13: Permit R13-2334, 9.3.1.]

- 9.3.2. The owner or operator of each source that is equipped with a closed vent system and control device as required in 40 CFR § 60.692-5 (other than a flare) is exempt from § 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

- a. Zero air (less than 10 ppm of hydrocarbon in air), and
- b. A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

[40 CFR § 60.696(b), 45CSR16, 45CSR13: Permit R13-2334, 9.3.2.]

9.4. Recordkeeping Requirements

- 9.4.1. Each owner or operator of a facility subject to the provisions of this subpart shall comply with the record keeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

[40 CFR § 60.697(a), 45CSR16, 45CSR13: Permit R13-2334, 9.4.1.]

- 9.4.2. a. For individual drain systems subject to 40 CFR § 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

- b. For junction boxes subject to 40 CFR § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.
- c. For sewer lines subject to 40 CFR §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(b), 45CSR16, 45CSR13: Permit R13-2334, 9.4.2.]

- 9.4.3. For oil-water separators subject to 40 CFR § 60.692-3, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-3(a) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(c), 45CSR16, 45CSR13: Permit R13-2334, 9.4.3.]

- 9.4.4. For closed vent systems subject to 40 CFR § 60.692-5 and completely closed drain systems subject to 40 CFR § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-5(e) during which detectable emissions are measured, or a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(d), 45CSR16, 45CSR13: Permit R13-2334, 9.4.4.]

- 9.4.5. a. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.
- b. The reason for the delay as specified in 40 CFR § 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.
- c. The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.
- d. The date of successful repair or corrective action shall be recorded.

[40 CFR § 60.697(e), 45CSR16, 45CSR13: Permit R13-2334, 9.4.5.]

- 9.4.6. a. A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.
- b. The following information pertaining to the design specifications shall be kept.
- i. Detailed schematics, and piping and instrumentation diagrams.
 - ii. The dates and descriptions of any changes in the design specifications.
- c. The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.
- i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with

a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

- ii. For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.
- iii. Dates of startup and shutdown of the closed vent system and control devices required in 40 CFR § 60.692 shall be recorded and kept for 2 years after the information is recorded.
- iv. The dates of each measurement of detectable emissions required in 40 CFR §§ 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.
- v. The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.
- vi. The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.
- vii. Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

[40 CFR § 60.697(f), 45CSR16, 45CSR13: Permit R13-2334, 9.4.6.]

- 9.4.7. For stormwater sewer systems subject to the exclusion in 40 CFR § 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

[40 CFR § 60.697(h), 45CSR16, 45CSR13: Permit R13-2334, 9.4.7.]

- 9.4.8. For ancillary equipment subject to the exclusion in 40 CFR § 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

[40 CFR § 60.697(i), 45CSR16, 45CSR13: Permit R13-2334, 9.4.8.]

- 9.4.9. For oil-water separators subject to 40 CFR § 60.693-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.693-2(a)(1)(iii)(A) and (B) and shall be maintained for the time periods specified in paragraphs a. and b. below.
- a. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.
- b. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(B), two years after the information is recorded.
[40 CFR § 60.697(k), 45CSR16, 45CSR13: Permit R13-2334, 9.4.9.]

9.5. Reporting Requirements

- 9.5.1. Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.
[40 CFR § 60.698(b)(1), 45CSR16, 45CSR13: Permit R13-2334, 9.5.1.]
- 9.5.2. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.
[40 CFR § 60.698(c), 45CSR16, 45CSR13: Permit R13-2334, 9.5.2.]
- 9.5.3. As applicable, a report shall be submitted semiannually to the Administrator that indicates:
- Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.
- Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in § 60.695(a)(3)(ii).
[40 CFR §§ 60.698(d)(3) and (d)(3)(ii), 45CSR16, 45CSR13: Permit R13-2334, 9.5.3.]
- 9.5.4. If compliance with the provisions of this subpart is delayed pursuant to 40 CFR § 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.
[40 CFR § 60.698(e), 45CSR16, 45CSR13: Permit R13-2334, 9.5.4.]

9.6. Compliance Plan

- 9.6.1. None.

10.0 Benzene Waste Operations Requirements from 40 CFR Part 61 Subpart FF

HAPs Emission Standards. The permitted facility shall comply with all applicable provisions of 45CSR34, which, by incorporation, subjects the facility to the provisions of 40 CFR 61 Subpart FF - National Emission Standard for Benzene Waste Operations, provided, however, that compliance with any more stringent limitation set forth under Conditions 5.1.6., 6.1.2. and 7.1.1. of this permit shall also be demonstrated.

[45CSR13: Permit R13-2334, Section 10.0.]

10.1. Limitations and Standards

10.1.1. An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of 40 CFR § 61.342 (b) and (c). The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

- a. Wastes that are exempted from control under 40 C.F.R. §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
- b. The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.
- c. Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of 40 C.F.R. §§ 61.342(c) through (h). If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
- d. The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in 40 C.F.R. § 61.355(c)(1)(i) (A) through (C).

[40 CFR § 61.342(a), 45CSR34, 45CSR13: Permit R13-2334, 10.1.1.]

10.2. Monitoring Requirements

10.2.1. Compliance with 40 CFR part 61 subpart FF will be determined by review of facility records and results from tests and inspections using methods and procedures specified in Sections 10.3.1. through 10.3.3. of this permit.

[40 CFR § 61.342(g), 45CSR34, 45CSR13: Permit R13-2334, 10.2.1.]

10.3. Testing Requirements

10.3.1. An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

- a. For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in 40 CFR § 61.342(a), the owner or operator shall:
 1. Determine the annual waste quantity for each waste stream using the procedures specified in Section 10.3.2. of this permit.
 2. Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in Section 10.3.3. of this permit.
 3. Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.
- b. Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to Section 10.3.2.b. of this permit.
- c. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:
 1. Comply with the record keeping requirements of 40 CFR § 61.356 and reporting requirements of 40 CFR § 61.357; and
 2. Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.
- d. The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in Section 10.3.2.b. of this permit, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with Sections 10.3.1. through 10.3.3. of this permit. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

[40 CFR § 61.355(a), 45CSR34, 45CSR13: Permit R13-2334, 10.3.1.]

10.3.2. For purposes of the calculation required by Section 10.3.1. of this permit, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in Sections 10.3.2.a. and b. of this permit, by one of the methods given in Sections 10.3.2. c. through e. of this permit.

- a. The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

- b. The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in Section 10.3.1.a.3. of this permit for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under 40 CFR § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.
- c. Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility.
- d. Use the maximum design capacity of the waste management unit; or
- e. Use measurements that are representative of maximum waste generation rates.

[40 CFR § 61.355(b), 45CSR34, 45CSR13: Permit R13-2334, 10.3.2.]

10.3.3. For the purposes of the calculation required by 40 CFR §§ 61.355(a), an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in Section 10.3.3.a. of this permit using either of the methods given in Sections 10.3.3.b. and c. of this permit.

- a. The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:
 - 1. The determination shall be made at the point of waste generation except for the specific cases given in Sections 10.3.3.a.1.A and B. of this permit.
 - A. The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.
 - B. The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in Sections 10.3.3.b. or c. of this permit. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in Section 10.3.1.a.3. of this permit for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.
 - 2. Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.
 - 3. Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination -- to reduce the benzene concentration.

4. The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in Sections 10.3.3.a.1.A. and B. of this permit.
 5. For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.
- b. *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under Section 10.3.3.c. of this permit shall be used to resolve the disagreement.
- c. Measurements of the benzene concentration in the waste stream in accordance with the procedures listed in 40 CFR § 61.355(c)(3).

[40 CFR § 61.355(c), 45CSR34, 45CSR13: Permit R13-2334, 10.3.3.]

10.4. Recordkeeping Requirements

- 10.4.1. Each owner or operator of a facility subject to the provisions of 40 CFR Part 61, subpart FF shall comply with the following record keeping requirements. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

[40 CFR § 61.356(a), 45CSR34, 45CSR13: Permit R13-2334, 10.4.1.]

- 10.4.2. Each owner or operator shall maintain records that identify each waste stream at the facility subject to 40 CFR Part 61, subpart FF, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition, the owner or operator shall maintain the following records:

- a. For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
- b. For each waste stream exempt from 40 CFR § 61.342(c)(1) in accordance with 40 CFR § 61.342(c)(3), the records shall include:
 1. All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute, or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with 40 CFR § 61.342(c)(3)(i), or

2. All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with 40 CFR § 61.342(c)(3)(ii).
- c. For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with 40 CFR § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with 40 CFR § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with 40 CFR § 61.355(a)(1)(iii) of this section.

[40 CFR § 61.356(b), 45CSR34, 45CSR13: Permit R13-2334, 10.4.2.]

10.5. Reporting Requirements

- 10.5.1. Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to 40 CFR § 61.342 and is determined by the procedures specified in 40 CFR § 61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:
 - a. Total annual benzene quantity from facility waste determined in accordance with 40 CFR § 61.355(a) of this subpart.
 - b. A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.
 - c. For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:
 1. Whether or not the water content of the waste stream is greater than 10 percent;
 2. Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;
 3. Annual waste quantity for the waste stream;
 4. Range of benzene concentrations for the waste stream;
 5. Annual average flow-weighted benzene concentration for the waste stream; and
 6. Annual benzene quantity for the waste stream.

- d. The information required in Sections 10.5.1.a., b., and c. of this Permit should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in 40 CFR § 61.10(a).

[40 CFR § 61.357(a), 45CSR34, 45CSR13: Permit R13-2334, 10.5.1.]

- 10.5.2. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in Section 10.5.1.a. through c. of this permit. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by Section 10.5.1.a. through c. is not changed in the following year, the owner or operator may submit a statement to that effect.

[40 CFR § 61.357(c), 45CSR34, 45CSR13: Permit R13-2334, 10.5.2.]

10.6. Compliance Plan

- 10.6.1. None.

11.0 [Internal Combustion Engines \(Emergency Generator and Firewater Pump Engines\) Requirements](#) [\[FWPUMP1 and FWPUMP2, CEG01\]](#)

11.1. Limitations and Standards

11.1.1. What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions? [\(For the fire pump engines identified as FWPUMP1 and FWPUMP2.\)](#)

If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d of 40 CFR 63 subpart ZZZZ that apply to you.

You must meet the following requirements, except during periods of startup. During periods of startup you must comply with Condition 11.2.1.b.

- a. Change oil and filter every 500 hours of operation or [within 1 year + 30 days of the previous change](#), ~~annually~~, whichever comes first; (Sources have the option to utilize an oil analysis program as described in Condition 11.2.1.c. in order to extend the specified oil change requirement.)
- b. Inspect air cleaner every 1,000 hours of operation or [within 1 year + 30 days of the previous inspection](#), ~~annually~~, whichever comes first, and replace as necessary; and
- c. Inspect all hoses and belts every 500 hours of operation or [within 1 year + 30 days of the previous inspection](#), ~~annually~~, whichever comes first, and replace as necessary.

[45CSR34, 40 CFR §63.6603(a) and Table 2d(1); 45CSR13: Permit R13-2334, 11.1.1.b, 2]

11.1.2. What are my general requirements for complying with this subpart? [\(For the fire pump engines identified as FWPUMP1 and FWPUMP2.\)](#)

- a. You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.
- b. At all times you 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. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. 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 §63.6605]

11.1.3. Firepump engines FWPUMP1 and FWPUMP2 shall not operate more than 500 hours each per year. Compliance with this limit shall be based on a rolling 12 month total.

[45CSR34, 45CSR13: Permit R13-2334, 11.1.1.a.]

[11.1.4. The following conditions and requirements are specific to the engine for generator set identified as COGEN \(CEG01\):](#)

- a. [Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for more than 50 hours per calendar year as described in 40 CFR §§60.4211\(f\)\(1\)](#)

through (3), for the engine are prohibited. Emergency operation/situations is defined when electric power from the local utility is interrupted from the facility.

1. There is no time limit on the use of the emergency stationary engine during emergency situations.
2. The permittee may operate the emergency stationary engine for the purpose specified in 40 CFR §60.4243(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by the following paragraph counts as part of the 100 hours per calendar year allowed by this paragraph.

The emergency stationary engine 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.

3. The emergency stationary engine 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 the above paragraph. 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, 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.
- b. The generator set shall be equipped with an engine or engine configuration that has been certified by the manufacturer to comply with either 40 CFR §60.4202(a)(2) or 40 CFR Part 60.
- c. The permittee shall operate and maintain the engine of the generator set according to the manufacturer's emission-related written instructions.
- d. The permittee shall only change those emission-related settings of the engine that are permitted by the manufacturer.
- e. The maximum nameplate power output of the engine for each generator set shall not be greater as listed in Table 1.0 of this permit.
- f. The engine shall be equipped with a non-resettable hour meter.
- g. The engine must use diesel fuel that meets the requirements in Condition 11.1.5. of this permit.
- h. The engine for CEG01 shall be a model year 2023 or later.
- i. You must meet the requirements of 40 CFR part 1068, as they apply to you.

[45CSR16; 40 CFR §60.4209(a), §60.4211(a), §60.4211(f); 45CSR13; Permit R13-2334, 11.1.2.]

- 11.1.5. Diesel fuel used by each engine for the generator set or firewater pump shall have a maximum sulfur content no greater than 15 ppm (ultra-low sulfur diesel) and with either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. Diesel meeting the specifications of Nonroad diesel under 40 CFR §80.510(b) is equivalent.

[45CSR16; 45CSR34; 40 CFR §60.4207(b), §1090.305 ~~§60.4205(b)~~; 45CSR13: Permit R13-2334, 11.1.3.]

11.1.6. The engine for generator set identified as COGEN (CEG01) must comply with the emission standards in 40 CFR §60.4202(a)(2) for all pollutants (i.e., the certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I for all pollutants and the smoke standards as specified in 40 CFR §1039). [45CSR16; 40 CFR §60.4205(b)]

11.1.7. The engine for generator set identified as COGEN (CEG01) must meet the emission standards of 40 CFR §60.4205 over the entire life of the engine. [45CSR16; 40 CFR §60.4206]

11.1.8. The certified engine for generator set identified as COGEN (CEG01) must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR §60.4211(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance pursuant to 40 CFR §60.4211(g) as follows:

You 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, you 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 you change emission-related settings in a way that is not permitted by the manufacturer. You 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(c), §§60.4211(g) and (g)(3)]

11.2. Monitoring Requirements

11.2.1. What are my monitoring, installation, collection, operation, and maintenance requirements? *(For the fire pump engines identified as FWPUMP1 and FWPUMP2.)*

- a. If you own or operate an existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. **[45CSR13: Permit R13-2334, 11.1.1, 4.]**
- b. If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Table 2d to 40 CFR subpart ZZZZ apply.
- c. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in Condition 11.1.1., you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency specified

for changing the oil [and filter](#) in Condition 11.1.1. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil [and filter](#). If any of the limits are exceeded, the engine owner or operator must change the oil [and filter](#) within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil [and filter](#) within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil [and filter](#) changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[45CSR34, 40 CFR §§63.6625(e), (e)(4), (h), and (i); [45CSR13: Permit R13-2334, 11.1.1.d.](#)]

11.2.2. **How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?** ([For the fire pump engines identified as FWPUMP1 and FWPUMP2.](#))

- a. You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in 40 CFR 63 subpart ZZZZ, Table 2d that apply to you according to methods specified in 40 CFR 63 subpart ZZZZ, Table 6 (same as Condition 11.2.1.a.)
- b. You must report each instance in which you did not meet each emission limitation or operating limitation in 40 CFR 63 part ZZZZ, Table 2d that apply to you. These instances are deviations from the emission and operating limitations in this subpart.

[45CSR34, 40 CFR §§63.6640(a), (b) and Table 6(9)]

11.2.3. [For the purpose of demonstrating compliance with the hours of operation limit in Condition 11.1.3. for Emission Units FWPUMP1 and FWPUMP2, the permittee shall record the number of hours each engine operated during the calendar month. Such records shall be maintained in accordance with Condition 3.4.2.](#) ~~For the purposes of determining compliance with 11.1.3., the permittee shall monitor and record the number of hours per month that fire water pump engines FWPUMP1 and FWPUMP2 operate.~~

[For the purpose of demonstrating compliance with the hours of operation limit Condition 11.1.4.a. for Emission Unit CEG01, the permittee shall record the number of hours each engine operated during the calendar month and the reason for such operation. For emergency operations, the permittee must document what is classified as the emergency for each emergency operation. The permittee shall maintain a calendar total of hours operated in non-emergency and emergency situations on a calendar year basis. Such records shall be maintained in accordance with Condition 3.4.2.](#)

[45CSR13: Permit R13-2334, 11.2.1.]

11.3. Testing Requirements

- 11.3.1. None.

11.4. Recordkeeping Requirements

11.4.1. **What records must I keep?**

- a. [For the fire pump engines identified as FWPUMP1 and FWPUMP2:](#) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs a.1. through a.4., and b.1.

1. A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).
 2. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
 3. Records of all required maintenance performed on the air pollution control and monitoring equipment.
 4. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition 11.1.2.b., including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
- b. [For the fire pump engines identified as FWPUMP1 and FWPUMP2: The permittee](#) ~~You~~ must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to [the permittee's](#) ~~your own~~ maintenance plan [for each RICE](#). ~~if you own or operate any of the following stationary RICE; [45CSR13: Permit R13-2334, 11.2.2.]~~
- ~~1. An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.~~

[45CSR34, 40 CFR §§63.6655(a), [\(e\)](#) and [\(e\)\(3\)](#); [45CSR13: Permit R13-2334, 11.2.2.](#)]

11.4.2. **In what form and how long must I keep my records?** [\(For the fire pump engines identified as FWPUMP1 and FWPUMP2.\)](#)

Your records must be in a form suitable and readily available for expeditious review according to 40 CFR §63.10(b)(1). As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[45CSR34, 40 CFR §§63.6660]

[11.4.3. For the certified engine for generator set identified as COGEN \(CEG01\): The owner or operator is not required to submit an initial notification. 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\(b\)\]](#)

11.5. Reporting Requirements

11.5.1. ~~None.~~ [For the fire pump engines identified as FWPUMP1 and FWPUMP2, you must report all deviations as defined in 40 CFR 63 Subpart ZZZZ in the semiannual monitoring report required by condition 3.5.6. You must also report each instance in which you did not meet the requirements in Table 8 to 40 CFR 63 Subpart ZZZZ that apply to you.](#)
[\[45CSR34; 40 CFR §63.6640\(e\), §63.6650\(f\)\]](#)

[11.5.2. If the engine for generator set identified as COGEN \(CEG01\) operates for the purpose specified in 40 CFR §60.4211\(f\)\(3\)\(i\), you must submit an annual report according to the following requirements](#)

- a. The report must contain the following information:
 - 1. Company name and address where the engine is located.
 - 2. Date of the report and beginning and ending dates of the reporting period.
 - 3. Engine site rating and model year.
 - 4. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
 - 5. 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. 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 this subpart 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. Submit the annual report electronically according to 40 CFR §60.4214(g).

[45CSR16; 40 CFR §60.4214(d)]

11.6. Compliance Plan

- 11.6.1. None.

APPENDIX A

45CSR2 & 45CSR10 Monitoring Plan

 Ergon - West Virginia, Inc.

9995 Ohio River Blvd, Post Office Box 356
Newell, West Virginia 26050-0356

Ms. Carrie McCumbers
WVDEP—Division of Air Quality
601 57th Street SE
Charleston, West Virginia 25304

RE: Monitoring Plan under 45 CSR 2 and 45 CSR 10

Dear Ms McCumbers:

Ergon West Virginia, Inc. (EWVI) is presenting the following monitoring plan as required under Title 45 of the Code of State Regulations (CSR) Series 2 and Series 10 (45 CSR 2 and 45 CSR10). The allowable emission rates for all of these units have been registered as part of air permit (R13-2334).

Boiler C:

This boiler is permitted to combust a combination of natural gas and refinery fuel gas (RFG) and has a design heat capacity (DHC) less than 100 MMBtu/hr.

Regulation 2

- **Opacity:** The combination of natural gas/RFG combusted within the boiler is very similar to natural gas. There is no probable cause that would indicate that opacity would be generated from the combustion of EWVI's RFG. Since natural gas combustion is exempt from visibility testing, EWVI requests that no visible emission testing be required when combusting RFG.
- **Weight Emission Testing:** Under permit R13-2334, EWVI has monthly and yearly limits on particulate (PM) emissions. EWVI documents PM emissions from Boilers A and B utilizing fuel usage records and regulatory limits. To demonstrate that these units operate will below allowable limits, EWVI proposes the following monitoring plan and request that no stack testing be required for the boilers.

Refinery fuel gas: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that significant particulate emissions from the combustion of EWVI's RFG, which is very similar to natural gas, would be generated.

- As required under §45-2-8.3.c, EWVI maintains records of the startup and shutdown of the boiler, and the quantity of fuel gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, this boiler cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boiler. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Boiler A and B:

These boilers combust a combination of natural gas and refinery fuel gas and have DHCs greater than 100 MMBtu/hr, but less than 250MMBtu/hr.

Regulation 2

- Opacity: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that opacity would be generated from the combustion of EWVI's RFG. Since natural gas combustion is exempt from visibility testing, EWVI requests that no visible emission testing be required when combusting RFG.
- Weight Emission Testing: Under permit R13-2334, EWVI has monthly and yearly limits on particulate (PM) emissions. EWVI documents PM emissions from Boilers A and B utilizing fuel usage records and regulatory limits. To demonstrate that these units operate will below allowable limits, EWVI proposes the following monitoring plan and request that no stack testing be required for the boilers.

Refinery fuel gas: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that significant particulate emissions from the combustion of EWVI's RFG, which is very similar to natural gas, would be generated.

- As required under §45-2-8.3.c, and §45-2A-7, EWVI maintains records of the startup and shutdown of the boilers, and the quantity of RFG combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, these boilers cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boilers. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Combustion Sources – H101R, H102R, H201, H501R, H500's, H600's, H701, H901

These units are process heaters and combust natural gas/refinery fuel gas combination fuel as their primary fuel. All of these units have DHCs between 10-100 MMBtu/hr, except H201, which has a DHC less than 10 MMBtu/hr.

Regulation 2

- **Opacity:** These heaters meet the requirements set forth in this regulation so therefore visible emission testing is indicated per §45-2-3.2. However, these units are exempt from testing and monitoring requirements since the DHCs of these units are less than 100 MMBtu/hr, per §45-2-8.4.c.
- **Weight Emission Testing:** Heater H201 is exempt from testing, monitoring, recordkeeping and reporting requirements as stipulated in §45-2-11, other than of course those requirements stated within the existing permit. The remaining heaters are less than 100 MMBtu/hr and therefore, are exempt from the periodic testing requirements in §45-2-8.1.a and the monitoring requirements in §45-2-8.2.
- As required in §45-2-8.3.c, and §45-2A-7, EWVI maintains records of the startup and shutdown of the heaters and the quantity of RFG and natural gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, these heaters cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boilers. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Combustion Sources-H441, H1101

The DHC for H441 is just over 10 MMBtu/hr and the DHC for H1101 is between 10-100 MMBtu/hr. These two heaters are fired with natural gas only.

Regulation 2

- As per the regulation §45-2-8.4.b and the guidance listed in §45-2A-3.1.a, since these heaters burn only natural gas, they are exempt from visible emission testing and weight emissions testing requirements.
- As required under §45-2-8.3.c, EWVI maintains records of the startup and shutdown of these heaters, and the quantity of natural gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10A-10.3, since these units combust only natural gas, they are exempt from the requirements in §45-10-8, which includes testing, monitoring, recordkeeping and reporting.

Manufacturing Process Sources-Main Flare

The flare is an emergency control device for the manufacturing process sources of the entire refinery.

Regulation 2

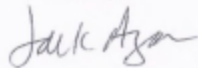
- Regulation 2 does not apply since this regulation only applies to indirect heat exchangers.

Regulation 10

- As indicated in §45-10A-5.2.b, process sources that utilize a flare as a control device are exempt from compliance testing requirements. Also EWWI has a flare gas recovery system on its flare.

If you have any questions or require additional information, please contact me at (304) 387-7046.

Sincerely,



Jack Azar
ESHT Manager

APPENDIX B

Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance Appendix A of R13-2334 (See 40 CFR §60.7(d))

Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO₂/NO_x/TRS/H₂S/CO/O₂)

Reporting period dates: From _____ to _____

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period¹

<u>Emission Data summary</u>	<u>CMS Performance Summary</u>
1. <u>Duration of excess emissions in reporting period due to:</u>	1. <u>CMS downtime in reporting period due to:</u>
a. <u>Startup/shutdown</u>	a. <u>Monitor equipment malfunctions</u>
b. <u>Control equipment problems</u>	b. <u>Non-Monitor equipment malfunctions</u>
c. <u>Process problems</u>	c. <u>Quality assurance calibration</u>
d. <u>Other known causes</u>	d. <u>Other known causes</u>
e. <u>Unknown causes</u>	e. <u>Unknown causes</u>
2. <u>Total duration of excess emission</u>	2. <u>Total CMS Downtime</u>
3. <u>Total duration of excess emissions × (100) [Total source operating time] %²</u>	3. <u>[Total CMS Downtime] x (100) [Total source operating time] %²</u>

¹ For gases, record all times in hours.

² For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process, or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name:

Signature:

Title:

Date:

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:
Ergon – West Virginia, Inc.
[Newell Refinery](#)
R30-02900008-2021

Laura M. Crowder
Director, Division of Air Quality

Issued: February 9, 2021 • Effective: February 23, 2021
Expiration: February 9, 2026 • Renewal Application Due: August 9, 2025

Permit Number: **R30-02900008-2021**
Permittee: **Ergon – West Virginia, Inc.**
[Facility Name: Newell Refinery](#)
Permittee Mailing Address: **[9995 Ohio River Blvd.](#), ~~P. O. Box~~ 356, Newell, WV 26050**

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:	9995 Ohio River Blvd., Newell, Hancock County, West Virginia
Telephone Number:	304-387-4343
Type of Business Entity:	Corporation
Facility Description:	Petroleum Refinery
SIC Codes:	2911
UTM Coordinates:	531.25 km Easting • 4495.35 km Northing • Zone 17

Permit Writer: Robert Mullins

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.

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

1.1. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
CDU	CDU	Crude Distillation Unit	1972/2012/2015	9,617,750 bbls/yr	00A-01
001-01	H-101R	CDU Atmospheric Heater; refinery fuel gas/natural gas blend	2012	54.5 MMBtu/hr	N/A
001-02	H-102R	CDU Vacuum Heater; refinery fuel gas/natural gas blend	2012	39.2 MMBtu/hr	N/A
002-01	H-201	PDR Heater; refinery fuel gas/natural gas blend	1972	6.6 MMBtu/hr	N/A
003-01	MEK-TOL	Solvent Dewaxing Unit	1972	N/A	N/A
004-01	H-500S	H500 Series Heaters (5 heaters to common stack) Unifiner/Platformer Unit; refinery fuel gas/natural gas blend	1972/2013/2016 ~~2015~~	59.6 MMBtu/hr	N/A
004-02	H-501R	Unifiner Charge Heater	2013	11.5 MMBtu/hr	N/A
005-01	H-600S	H600 Series Heaters, (4 heaters to common stack) ISOMAX Unit; refinery fuel gas/natural gas blend	1972	41.6 MMBtu/hr	N/A
005-02	H-441	Hydrogen Plant Heater; natural gas	1972	12.3 MMBtu/hr	N/A
006-01	H-701	VFU Heater; refinery fuel gas/natural gas blend	1983	12.1 MMBtu/hr	N/A
EPN 01	H-901	DHT Heater	2005	27.5 MMBtu/hr	n/a
EPN 03	H-1101	Hydrogen Plant Heater	2005	38.8 MMBtu/hr	n/a
007-01	Boiler A	Boiler A; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	N/A
007-02	Boiler B	Boiler B; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	N/A
007-03	Boiler C	Boiler C; refinery fuel gas/natural gas blend	2000	95 MMBtu/hr	N/A
TDB01	TDB01	Solar Titan 130-23001S Natural Gas Fired Combustion Turbine (CT) with generator coupled with heat recovery steam generator (HRSG)	2025	15 MW (gross output)	n/a
		Refinery fuel gas/natural gas blend fired duct burner		77.6 MMBtu/hr	n/a
CCT01	CCT01	COGEN Fluid Cooler (closed circuit cooling unit)	2025	2,016 GPM	n/a
Portable Boiler	Portable Boiler	Portable Boiler; Natural Gas	2020	99.9 MMBtu/hr Max	N/A
009-01	T Load	Truck Loading	1972/2012/2013	397.8 MMgal/yr	00A-02*

Commented [GM1]: Duplicate of EPN 01 and 03 (with next page).

Commented [FT2R1]: See below

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
Rail-UL	Rail-UL	Rail Car Unloading	2019	800 gpm	N/A
009-02	MLD	Marine Barge Loading	1972/2012	460.7 MMgal/yr	00A-04**
00A-01	F1	Main Flare	1972	N/A	N/A
00A-03	F2	Sour Gas Flare	1972	N/A	N/A
00A-02	OXIDIZER	Thermal Oxidizer - 98.7% Min Efficiency	1994/2012 /2013	17,346 MMBtu/yr	N/A
00A-04	MLDOX	Barge Loading Thermal Oxidizer - 98% Min Eff	2012	59.0 MMBtu/hr	N/A
00B-01	WWT	Wastewater Treatment Plant	1972/1997	600 gpm	00A-03
00B-02	EQLEAKS	Equipment Leak Fugitives	N/A	N/A	N/A
00D-01	Dehy Htr	Dehydration Heater	1991	0.59 MMBtu/hr	N/A
00D-02	Still	Glycol Dehydration Still	1991	N/A	N/A
~~EPN-01~~	~~H-901~~	~~DHT Heater~~	~~2005~~	~~27.5 MMBtu/hr~~	~~N/A~~
EPN-03	H-1101	Hydrogen Plant Heater	2005	38.8 MMBtu/hr	N/A
FWPUMP1	FWPUMP1	Diesel Firewater Pump at River Dock	2005	210 hp	N/A
FWPUMP2	FWPUMP2	Diesel Firewater Pump at Boiler House	1993	265 hp	N/A
CEG01	CEG01	COGEN Black-Start Deisel Emergency Generator (Generac Model S12R-Y2PTAQ-1; Model Yr. 2023 or later)	2025	1,881 HP	N/A
Tanks					
4000	TK-4000	External floating roof; crude oil; mechanical shoe	1992/2012	2,310,000 gallons	N/A
4001	TK-4001	External floating roof; crude oil; mechanical shoe	1973/2012	2,310,000 gallons	N/A
4002	TK-4002	External floating roof; heavy products or kerosene; mechanical shoe	1970	2,310,000 gallons	N/A
4003	TK-4003	External floating roof; heavy products or kerosene; mechanical shoe	1970	2,310,000 gallons	N/A
4004	TK-4004	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4005	TK-4005	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4006	TK-4006	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4007	TK-4007	Fixed roof; heavy products	1971	2,310,000 gallons	N/A
4008	TK-4008	Fixed roof; heavy products	1970	1,260,000 gallons	N/A
4009	TK-4009	Fixed roof; heavy products or kerosene	1971	1,260,000 gallons	N/A
4010	TK-4010	Fixed roof; heavy products	1970	1,260,000 gallons	N/A

Commented [CG3]: Remove duplicate.

Commented [FT4R3]: The duplication has been previously corrected following an internal review. These heaters have been relocated in the table with the other heaters.

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
4011	TK-4011	Fixed roof; heavy products or kerosene	1971	1,239,568 gallons	N/A
4012	TK-4012	Internal floating roof; gasoline; vapor mounted	1971	630,000 gallons	N/A
4013	TK-4013	Internal floating roof; gasoline; vapor mounted	1971	630,000 gallons	N/A
4014	TK-4014	External floating roof; gasoline; mechanical shoe	1971/2013	315,000 gallons	N/A
4015	TK-4015	External floating roof; gasoline; mechanical shoe	1971/2013	315,000 gallons	N/A
4016	TK-4016	External floating roof; gasoline; mechanical shoe	1971	315,000 gallons	N/A
4017	TK-4017	Fixed roof; heavy products	1971	840,000 gallons	N/A
4018	TK-4018	Fixed roof; heavy products	1971/2000	704,970 gallons	N/A
4019	TK-4019	Fixed roof; heavy products	1971	704,970 gallons	N/A
4020	TK-4020	Fixed roof; heavy products	1971	840,000 gallons	N/A
4021	TK-4021	Fixed roof; heavy products	1971	840,000 gallons	N/A
4022	TK-4022	Fixed roof; heavy products	1971	571,200 gallons	N/A
4023	TK-4023	Fixed roof; heavy products	1971	571,200 gallons	N/A
4024	TK-4024	Fixed roof; heavy products	1970	840,000 gallons	N/A
4025	TK-4025	Fixed roof; heavy products	1970	840,000 gallons	N/A
4026	TK-4026	Fixed roof; heavy products	1970	840,000 gallons	N/A
4027	TK-4027	Fixed roof; heavy products	1971	840,000 gallons	N/A
4028	TK-4028	Fixed roof; heavy products	1970	210,000 gallons	N/A
4029	TK-4029	Fixed roof; heavy products	1971	65,100 gallons	N/A
4030	TK-4030	Fixed roof; heavy products	1971	65,100 gallons	N/A
4031	TK-4031	Fixed roof; heavy products	1971	315,000 gallons	N/A
4032	TK-4032	Fixed roof; heavy products	1971	315,000 gallons	N/A
4033	TK-4033	Fixed roof; heavy products	1970	315,000 gallons	N/A
4034	TK-4034	Fixed roof; heavy products	1998	840,000 gallons	N/A
4035	TK-4035	Fixed roof; heavy products	1983	840,000 gallons	N/A
4036	TK-4036	Fixed roof; heavy products	1973	315,000 gallons	N/A
4037	TK-4037	Fixed roof; heavy products	1973	315,000 gallons	N/A
4038	TK-4038	Fixed roof; heavy products	1976	840,000 gallons	N/A
4039	TK-4039	Fixed roof; heavy products	1977	1,260,000 gallons	N/A
4040	TK-4040	Fixed roof; heavy products	1978	630,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
4041	TK-4041	Fixed roof; heavy products	1973	630,000 gallons	N/A
4042	TK-4042	Fixed roof; heavy products	1978	630,000 gallons	N/A
4043	TK-4043	Fixed roof; heavy products	1978	630,000 gallons	N/A
4044	TK-4044	Fixed roof; heavy products	1982	1,260,000 gallons	N/A
4045	TK-4045	Fixed roof; heavy products	1982	630,000 gallons	N/A
4046	TK-4046	Fixed roof; heavy products	1982	630,000 gallons	N/A
4047	TK-4047	Fixed roof; heavy products, MTVP <3.5kPa	1986	1,260,000 gallons	N/A
4048	TK-4048	Fixed roof; heavy products	1986	504,000 gallons	N/A
4050	TK-4050	Internal floating roof; gasoline; mechanical shoe	1993/2013	630,000 gallons	N/A
4051	TK-4051	Fixed roof; heavy products, MTVP <3.5kPa	1996	1,260,000 gallons	N/A
4052	TK-4052	Fixed roof; ethanol	1972	30,240 gallons	N/A
4053	TK-4053	Fixed roof; ethanol	1972	30,240 gallons	N/A
4054	TK-4054	Fixed roof; heavy products or kerosene	1998	625,000 gallons	N/A
4055	TK-4055	Fixed roof; heavy products or kerosene	1998	625,000 gallons	N/A
4056	TK-4056	Fixed roof; heavy products or kerosene	1999	625,000 gallons	N/A
4057	TK-4057	Fixed roof; heavy products or kerosene	1999	625,000 gallons	N/A
4060	TK-4060	Internal floating roof; crude; mechanical shoe	1999/2012 /2015	5,040,000 gallons	N/A
4061	TK-4061	Internal floating roof; crude; mechanical shoe	2008/2012 /2015	5,040,000 gallons	N/A
4062	TK-4062	Internal floating roof; light crude oil with vapor pressure < 11.0 psia; mechanical shoe	2008/2012	5,040,000 gallons	N/A
4063	TK-4063	Internal floating roof; light crude oil with vapor pressure < 11.0 psia; mechanical shoe	2012	5,040,000 gallons	N/A
4066	TK-4066	Fixed roof; Biodiesel Tank	2011	40,000 gallons	N/A
4069	TK-4069	Fixed roof; Biodiesel Tank	2017	126,000 gallons	N/A
4070	TK-4070	Internal floating roof; ethanol; mechanical shoe	2018	630,000 gallons	N/A
4071	TK-4071	External floating roof; gasoline; mechanical shoe	2018	1,260,000 gallons	N/A
4072	TK-4072	Fixed roof; feedstock	2018	1,260,000 gallons	N/A
4073	TK-4073	Fixed roof; heavy products	2020	32,800 barrels	N/A
4103	TK-4103	Fixed roof; heavy products	1970	127,000 gallons	N/A
4104	TK-4104	Fixed roof; heavy products	1970	127,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
V-4002	V-4002	NGL Bullet Tank	2016	10,984 ft ³	fuel gas system
V-4003	V-4003	NGL Bullet Tank	2016	10,984 ft ³	fuel gas system
00A-03	CARBONBED	Carbon Bed Adsorber	2002	6,000 cfm	N/A
Process Vessels					
303	TK-303	Fixed roof; MEK	1970	7,875 gallons	N/A
304	TK-304	Fixed roof; Toluene	1970	7,875 gallons	N/A
NS-FUG	NS-FUG	Naphtha Splitter Fugitives	2011	N/A	N/A
ISOM	ISOM	Processing Unit: Benzene Reduction	2012	21.6 MMgals/yr	N/A
ADU	NH3OX	Ammonia Destruction Unit	2015	N/A	00A-05
00A-05	NH3OX	Ammonia Destruction Unit Thermal Oxidizer - 99.9% DRE	2015	6.6 MMBtu/hr	N/A
ADUFUG	ADUFUG	Ammonia Destruction Unit Fugitives	2015	N/A	N/A
PL-FUG	PL-FUG	Platformer Expansion Fugitives	2015	N/A	N/A
YNGL-FUG	YNGL-FUG	Y-Grade NGL Fugitives	2015	N/A	N/A

* Control Device for Gasoline Loading Only

** Control Device for Gasoline and Light Crude Oil Loading Only

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- ~~2334AK~~ A1	~~August 22, 2025~~ September-23, 2021

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 ~~such~~ 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~~, ~~2.12~~). 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	PM₁₀	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	SO₂	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		
mmft³/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 39]

2.12. Reasonably Anticipated Operating Scenarios

- 2.12.1. The following are terms and conditions for reasonably anticipated operating scenarios identified in this permit.
- 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.
 - The permit shield shall extend to all terms and conditions under each such operating scenario; and
 - 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:
- 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;
 - Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
 - 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;
 - 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:
- 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
 - 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~~ Emergency

- ~~2.17.1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.~~
- ~~[45CSR§30-5.7.a.]~~

- ~~2.17.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of 45CSR§30-5.7.e. are met.~~
- ~~[45CSR§30-5.7.b.]~~

- ~~2.17.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:~~
- ~~An emergency occurred and that the permittee can identify the cause(s) of the emergency;~~
 - ~~The permitted facility was at the time being properly operated;~~
 - ~~During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and~~

~~d.— Subject to the requirements of 45CSR§30-5.1.e.3.C.1, the permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice, report, and variance request fulfills the requirement of 45CSR§30-5.1.e.3.B. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.~~

~~[45CSR§30-5.7.e.]~~

~~2.17.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.~~

~~[45CSR§30-5.7.d.]~~

~~2.17.5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.~~

~~[45CSR§30-5.7.e.]~~

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. and ~~45CSR38~~

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 14)]
- 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:
- 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.
 - 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.** This stationary source, as defined in 40 CFR § 68.3, is subject to Part 68. This stationary source has submitted a risk management plan (RMP) by the date specified in 40 CFR §68.10. This stationary source shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 CFR Part 70 or 71.

[40 CFR 68]

- 3.1.9. **Sulfur Dioxide.** The Company agrees that it shall not operate any source of sulfur dioxide emissions unless such source is in compliance with the Code, terms of CO-SIP-95-1, and any additional or more stringent provisions of 45CSR10 - "To Prevent and Control Air Pollution From the Emissions of Sulfur Oxides".

[CO-SIP-95-1 - IV.1. (SIPed)]

- 3.1.10. **Sulfur Dioxide.** The Company agrees that at all times, including periods of source start-up, shut down, and malfunction, that it will, to the extent practicable, maintain and operate all sources of sulfur dioxide emissions, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.

[CO-SIP-95-1 - IV.2. (SIPed)]

- 3.1.11. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, operate, and maintain 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.

[45CSR13: Permit R13-2334, [4.1.20](#), ~~4.1.5~~, 45CSR§13-5.10, ~~11~~.]

- 3.1.12. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-2334 through R13-~~2334AK~~ **AIF** and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to.

[45CSR13: Permit R13-2334, 2.5.1.]

- 3.1.13. Facility wide emissions of all combined HAPs (including combustion related HAPs) shall not exceed 24.99 tons per year. Facility wide emissions of any individual HAP (including combustion related HAPs) shall not exceed 9.99 tons per year. Compliance with this condition shall be determined using a rolling 12 month total.

[45CSR13: Permit R13-2334, 12.1.1]

3.2. Monitoring Requirements

- 3.2.1. In order to determine compliance with this condition, the applicant shall calculate facility wide emissions of HAPs on a monthly basis. Said emission calculations shall be based on one of the following:
 - a. Continuous Emissions Monitoring
 - b. Predictive Emissions Monitoring

- c. USEPA approved source testing
- d. Material balance
- e. AP-42
- f. Manufacturer's Data

[45CSR13: Permit R13-2334, 12.2.1]

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 in 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)(~~14-15-16~~) 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.; R13-2334, 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.]

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 Maintenance of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures. [45CSR13: Permit R13-2334, Condition 4.4.2.]

3.4.5. **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: Permit R13-2334, Condition 4.4.3.]

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](#) ~~Section~~ (3ED21)
[Four Penn Center](#)
[1600 John F. Kennedy Boulevard](#) ~~1650 Arch Street~~
Philadelphia, PA 19103-~~2852~~ 2029

DAQ Compliance and Enforcement¹:

DEPAirQualityReports@wv.gov

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

- 3.5.4. ~~**Fees, Certified emissions statement.**~~ The permittee shall ~~submit a certified emissions statement and~~ pay fees on an annual basis in accordance with [45CSR§30-8](#). ~~the submittal requirements of the Division of Air Quality.~~
[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:

DEPAirQualityReports@wv.gov

US EPA:

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. Emergencies.**~~ ~~For reporting emergency situations, refer to Section 2.17 of this permit.~~

- 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. Any deviation resulting from an emergency or upset condition, as defined in 45CSR§30-5.7., shall be reported by telephone or telefax within one (1) working day of the date on which the permittee becomes aware of the deviation, if the permittee desires to assert the affirmative defense in accordance with 45CSR§30-5.7. A written report of such deviation, which shall include the probable cause of such deviations, and any corrective actions or preventative measures taken, shall be submitted and certified by a responsible official within ten (10) days of the deviation.~~
 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~~ [telefax](#). 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. EWVI has certified that it has completed its obligations from the Consent Judgment (97-C-338), therefore the requirements from the Consent Judgment are no longer included in the Title V Permit.

- b. 40 CFR Part 60, Subpart D - The boilers at the Newell Refinery do not have rated capacities greater than 250 MMBTU/hr.
- c. 40 CFR Part 60, Subpart Da - The boilers at the Newell Refinery are not in electric utility service and do not have rated capacities greater than 250 MMBTU/hr.
- d. 40 CFR Part 60, Subpart Db - The Newell Refinery does not have steam generating units that commenced construction, modification or reconstruction after June 19, 1984 with a rated capacity greater than 100 MMBTU/hr.
- e. 40 CFR Part 60 Subpart Dc - National Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units does not apply to process heaters H-101R, H-102R, and H-501R because although they have maximum design heat inputs between 10 and 100 MMBtu/hr, they do not meet the definition of a “steam generating unit.” The Portable Boiler is also not subject to this subpart since it is defined as a temporary boiler and per 40 C.F.R. §60.40c(i), “temporary boilers” are not subject to the subpart.
- f. 40 CFR Part 60 Subpart RRR - National Standards of Performance for Volatile Organic Compounds (VOC) Emissions from Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Reactor Processes does not apply to EWVI since it does not produce any of the chemicals listed in 40 CFR §60.707 as a product, co-product, by-product, or intermediate.
- g. 40 CFR Part 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene. The provisions of this subpart apply to each of the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges, and other connectors, product accumulator vessels, and control devices or systems required by this subpart. To be covered by this Subpart, the equipment must be in benzene service. In benzene service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The Newell Refinery does not have any equipment that is in benzene service.
- h. 40 CFR Part 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources). The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air pollutant service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges, and other connectors, product accumulator vessels, and control devices or systems required by this subpart.

The provisions of this subpart apply after the promulgation of a specific subpart in Part 61. For example, If the refinery was subject to 40 CFR Part 61, Subpart J (which it is not), then the refinery would have to comply with the equipment leak provisions of 40 CFR Part 61, Subpart V. The actual equipment leak standards are contained in Subpart V. If one is subject to Subpart J, then Subpart J refers one to Subpart V for the actual compliance standards. In summary, the Newell Refinery would have to be subject to some other subpart in Part 61 that referred to Subpart V before Subpart V would be applicable.

- i. 40 CFR Part 63 - EWVI has demonstrated that the facility is not a major source of HAPs and never has been. MEK is a major constituent of the EWVI HAP emissions and has now been delisted. [70 Fed. Reg. 75047 (December 19, 2005)] Further, EPA has made the determination that the delisting of MEK may be applied retroactively. Therefore, the “once in, always in” policy would not apply. In addition,

more accurate emissions calculation methodologies have been developed for estimating fugitive emissions. Applying the more accurate emissions methodologies demonstrates that emissions from the MEK-TOL unit never exceeded the major threshold, even when combined with other sources of HAP emissions at the refinery. Retroactively applying the more accurate calculation methods for determining fugitive emissions from the MEK-TOL unit, added to the rest of the facility's HAP emissions, determined that facility-wide HAP PTEs have always been less than 10 tons per year of a single HAP and 25 tons per year of aggregate HAPs. Therefore, 40 CFR Part 63, Subparts H, R, Y, CC, OO, PP, QQ, RR, VV, UUU, EEEE, [YYYY](#), GGGGG, and DDDDD do not apply to this source.

- j. 40 CFR Part 63 Subpart JJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers, which is an area source MACT rule, does not apply to EWVI's boilers and process heaters per 40 CFR §63.11195 (e), since they are gas fired.

4.0 Fuel Burning Units Requirements [Boilers A, B, & C, Portable Boiler, [Process](#) Heaters H-101R, H-102R, H-201, H-500S, H-501R, H-600S, H-441, H-701, H-901, and H-1101; [Combustion Turbine w/Duct Burner](#)]

Emission Unit	Applicable Rule	Limits Section 4.1:	Monitoring Section 4.2:	Testing Section 4.3:	Recordkeeping Section 4.4:	Reporting Section 4.5
Boilers A&B	45CSR2	1, 2, 3, 4, 7, 8, 9	3		2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5, 8	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 14, 25	1, 3, 8, 9, 13		1, 2, 3, 4, 5, 6, 8	1, 2
	CO-SIP-95	15, 16	2, 4, 5, 6, 7, 9	2, 3	7, 8	3, 4
Boiler C	40CFR60	9, 12, 25	9		6	
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13, 17	8		4, 5	
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 17, 25	1, 8, 9, 10, 11		1, 2, 3, 4, 5, 9	1, 5, 6
	CO-SIP-95		9	3		
	40CFR60	9, 12, 25	9			5
Portable Boiler	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 28, 29, 30, 31, 32	1, 15		2, 3, 19, 20	1
H-101R & H-102R	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 18, 26, 27	1, 8, 14	1	1, 2, 3, 4, 5, 12, 18	1, 2, 8, 9
	40CFR60	9, 18, 26, 27	14	1	16	8, 9
H-201	45CSR2	1, 2, 3, 4				
	45CSR10	5			14	
	45CSR13	1, 3, 4, 6, 12, 19, 25	1, 9		1, 6, 14	
	CO-SIP-95		2, 9, 10	2, 3	7, 14	3, 4
	40CFR60	12, 25	9		6	
H-441	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 19				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 10, 11, 19, 20	1		1, 2, 3, 13	1
	CO-SIP-95	20	2, 7			3, 4
	40CFR60	9				
H-701	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13, 19	8		4, 5, 14	
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 19, 25	1, 8, 9		1, 2, 3, 4, 5, 6, 14	1
	CO-SIP-95	21	2, 7, 9	2, 3	7, 14	3, 4
	40CFR60	9, 12, 25	9		6	
H-500S & H-600S	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5, 14	2
	CO-SIP-95		2, 7, 9, 10	2, 3	7, 14	3, 4
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 22, 25	1, 8		1, 2, 3, 4, 5, 14	1, 2
	500S only	26	14	1	18	8, 9
	600S only	12	9		6	
	40CFR60	9, 25		1		8, 9
	500S only	26	14		18	

Emission Unit	Applicable Rule	Limits Section 4.1.	Monitoring Section 4.2.	Testing Section 4.3.	Recordkeeping Section 4.4.	Reporting Section 4.5
	600S only	12	9		6	
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5	2
H-501R	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 18, 26, 27	1, 8, 14	1	1, 2, 3, 4, 5, 12, 18	1, 2, 8, 9
	40CFR60	9, 18, 26, 27	14	1	18	8, 9
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8			2
H-901	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 23, 25	1, 8, 9, 11		1, 2, 3, 6, 15, 16	1, 2, 7
	CO-SIP-95		9	3	7	
	40CFR60	9, 12, 25	9		6	7
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
H-1101	45CSR10	5, 10, 11				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 23, 24	1, 12		1, 2, 3, 17	1

4.1. Limitations and Standards

All boilers and heaters

4.1.1.1. Boilers A and B are “fuel gas combustion device” under Subpart J of 40 CFR 60. Boilers A and B are “fuel burning units” under 45CSR2 and 45CSR10; and “combusting refinery gas stream” in Section 5 of 45CSR10. The following conditions and requirements are specific to boilers identified as Boiler A and Boiler B: 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.

a. The emissions released from each Emission Points “Boiler A” and “Boiler B” shall not exceed following individual emission rates.

CO & VOC limits for Boilers A and B		
Pollutant	Emission Rate	
	TPM	TPY
CO	5.76	57.54
VOC	0.38 ~~3.77~~	3.79

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NOx emissions from the respective emission point of each boiler shall not exceed 0.058 lb/MMBtu on a three (3) hour rolling average basis.
- c. PM emissions from the respective emission points of each boiler shall not exceed 1.44 pounds per hour on a 6-hour average basis. Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.
- d. Each boiler shall not exhibit visible emissions from respective emission points greater than 10% opacity on a six (6) minute average basis.

Commented [FT5]: Added as revised in R13-2334AK.

Commented [CG6]: Current permit limit is 0.75 tpm.

Commented [GM7R6]: There is a slipped decimal on the 3.77; as it should be 0.377 or 0.38 (for single unit; old 0.75 tpm is for 2 units).

Commented [FT8R6]: Corrected.

e. ~~Each boiler shall be fired with refinery fuel gas (RFG) that meets the requirements in Conditions 4.1.16 and 4.1.17.~~

e. ~~Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limits in 45CSR§10-3.1.5 and CO-SIP-95-1 - Condition IV.3.B.b.~~

f. ~~Any modifications or replacement of the stacks from Boilers No. A and B shall comply with the provisions of 45CSR20 "Good Engineering Practice as Applicable to Stack Heights".~~

~~[45CSR§2-3.1.; 45CSR2-4.1.2.; 45CSR§10-3.1.5.; CO-SIP-95-1 - Conditions IV.3.B.b. and IV.10. (SIPed); and 45CSR13: Permit R13-2334, 4.1.1.]~~

4.1.2. 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 Director. 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 Director.

~~[45CSR§2-4.4.]~~

4.1.3. ~~Boiler C is a "fuel gas combustion device" under Subpart Ja; "fuel burning unit" under 45CSR2 and 45CSR10; and "combusting refinery gas stream" in Section 5 of 45CSR10. The following conditions and requirements are specific to the boiler identified as Boiler C: In the event of an unavoidable shortage of fuel having characteristics or specifications necessary for a fuel burning unit to comply with the visible emission standards set forth in 45CSR§2-3.1. or any emergency situation or condition creating a threat to public safety or welfare, the Director may grant an exception to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during the exception period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the emission standards under 45CSR§2-4.1.b. will not be exceeded during the exemption period.~~

~~[45CSR§2-10.1. and 45CSR13: Permit R13-2334, 4.1.2.]~~

a. ~~The emissions released from Emission Points "Boiler C" shall not exceed following individual emission rates.~~

Emission Limits for Boiler C		
Pollutant	Emission Rate	
	TPM	TPY
CO	3.43	34.27
VOC	0.22	2.24

~~TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.~~

b. ~~NO_x emissions from Emission Point "Boiler C" shall not exceed 0.050 lb/MMBtu on a three-hour average basis. Boiler C shall be equipped with low NO_x burners.~~

c. ~~PM emissions from Emission Point "Boiler C" shall not exceed 0.86 pounds per hour on a 6-hour average basis. Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.~~

d. ~~Boiler C shall not exhibit visible emissions from Emission Point "Boiler C" greater than 10% on a six (6) -minute average basis.~~

Commented [FT9]: Added 4.1.16, as revised in R13-2334AK.

Since the CO SIP requirement is still applicable, it has been streamlined here as opposed to adding a separate less stringent requirement.

Commented [CG10]: General comment: putting all the citations at the end of the sections makes it difficult to understand the underlying requirement for the individual conditions, which have different basis. It also makes it nearly impossible to QA these citations. Recommend placing each applicable underlying requirement after each sub-condition. Recommend updating as part of the renewal.

Commented [FT11R10]: The usual practice is to include all of the applicable requirement citations at the end of the permit condition as it was done here. Your request can be further examined during the processing of the renewal permit.

- e. The boiler shall either combust natural gas or “fuel gas” that meets the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.

[45CSR§2-3.1.; 45CSR2-4.1.2.; 45CSR§10-3.1.5.; 45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); and 45CSR13: Permit R13-2334, 4.1.2.]

- 4.1.4. The following conditions and requirements are specific to Combustion Turbine #1 with duct burner, which is referred to as TBD01: The TBD01 duct burner is a “fuel gas combustion device” under Subpart Ja; TBD01 is a “fuel burning unit” under 45CSR2 and 45CSR10; ~~In the event a fuel burning unit employing a flue gas desulfurization system must by-pass such system because of necessary planned or unplanned maintenance, visible emissions may not exceed twenty percent (20%) opacity during such period of maintenance. The Director may require advance notice of necessary planned maintenance, including a description of the necessity of the maintenance activity and its expected duration and may limit the duration of the variance or the amount of the excess opacity exception herein allowed. The Director shall be notified of unplanned maintenance and may limit the duration of the variance or the amount of excess opacity exception allowed during unplanned maintenance.~~
[45CSR§2-10.2. and 45CSR13: Permit R13-2334, 4.1.3.]

- a. Emissions from TBD01 shall not exceed the following:

- i. TBD01 shall not discharge nitrogen oxides (NO_x) emissions in excess of 1.2 lb of NO_x per MWh on a 30-day rolling average basis.
- ii. TBD01 shall not discharge sulfur dioxide (SO₂) emissions in excess of 0.90 lb of SO₂/MWh on a gross output basis or 0.060 lb of SO₂/MMBtu on a heat input basis.

Compliance with the heat input standard limit shall be satisfied with either current, valid purchase contract, tariff sheet or transportation contract for the natural gas specifying that the maximum total sulfur content for the natural gas is no greater than 20 grains per 100 cubic feet of gas, consuming a gaseous fuel (refinery fuel gas) that does not exceed 0.060 lb SO₂/MMBtu heat input based fuel monitoring outline in Condition 4.2.9., or combination of these methods for each type of fuel consumed by the turbine.

- b. Mass hourly emissions from Emission Point TDB01 shall not exceed the following limits regardless of the operation of the duct burner:

Emission Limit for Emission Point TDB01		
Pollutant	Emission Rate	
	Hourly Limit (lb/hr)	Annual Limit (TPY)
CO	12.55	56.35
PM ₁₀ /PM _{2.5}	1.81	7.92
VOC	1.50	6.96
Formaldehyde	0.13	0.56
Total HAPs	0.32	1.38

Commented [FT12]: The language has been added as revised in R13-2334AK.

Only the hourly CO and VOC limits in the above table do not apply during startup and shutdown events.

- c. At all times when the duct burner is firing, visible emissions from Emission Point TDB01 shall not be greater than ten (10) percent opacity based on a six-minute average.
- d. At all times when the duct burner is firing, PM emissions from Emission Point TDB01 shall not exceed 1.23 pounds per hour on a 6-hour average basis. *Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.*
- e. Annual mass NO_x emissions from Emission Point TDB01 shall not exceed 39.95 tons per year on a 12-month rolling total basis. This limit shall include NO_x emissions due to the startup events, shutdown events, operating in SoLoNO_xTM mode, operation in non-SoLoNO_xTM mode from the combustion turbine, and NO_x emissions from the duct burner. Any future relaxation of this limit shall only be authorized in accordance with 45CSR14.
- f. The permittee must operate and maintain the 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.

The permittee shall operate TBD01 at a load condition that allows ~~the~~ for the operation of the SoLoNO_xTM mode with the Enhanced Emission Control Systems to be engaged at all times except during startup and shutdown events and when ambient air temperatures are below 0 F. The permittee must minimize the time spent during startup and shutdown events which shall not exceed 180 minutes per startup event. Ending/completion of the startup event shall be defined once the CT has reached the 50% load. Once the combustion turbine has successfully started up, the permittee shall in a timely manner increase the loading on the combustion turbine to engage the SoLoNO_xTM mode with the Enhanced Emission Control Systems to minimize emissions. Operating the combustion turbine at idle conditions is not permitted except when transitioning from a successful startup event to a load condition that the SoLoNO_xTM mode can be engaged or when transiting from normal operations with SoLoNO_xTM mode operating to a shutdown event. Monitoring the status of the SoLoNO_xTM operating mode shall be conducted using the parameters with associated operating ranges for the system stated by the turbine manufacture's latest written specifications (e.g., PIL 220).

Commented [FT13]: Deleted.

- g. The duct burner is limited to consuming "fuel gas" meeting the specifications stated in Conditions 4.1.15, and 4.1.17. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*
- h. The maximum amount of energy inputted into the combustion turbine shall not exceed 172 MMBtu/hr on a 24-hour average basis.
- i. The maximum amount of energy input from the duct burner shall not exceed 77.6 MMBtu/hr on a 24-hour average basis.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§§10-3.1.5. & 3.8.; 45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); 40 CFR §60.4320(a), Table 1 to 40 CFR 60 Subpart KKKK, §§60.4330(a)(1) & (a)(2), §60.4333(a), §60.4365(a), §60.4415(a)(1); and 45CSR13: Permit R13-2334, 4.1.4.]

- 4.1.5. Heater H-101R is a "fuel gas combustion device" under Subpart Ja of 40 CFR 60; and "process heater" under Subpart Ja of 40 CFR 60, ~~45CSR2~~, and 45CSR10. The following conditions and requirements are specific to

Commented [FT14]: 45CSR2 has been added as revised in R13-2334AK.

Heater H-101R for the crude distillation unit: ~~Due to unavoidable malfunction of equipment or inadvertent fuel shortages, emissions exceeding those provided for in 45CSR10 may be permitted by the Director for periods not to exceed ten (10) days upon specific application to the Director. Such application shall be made within twenty-four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Director provided a corrective program has been submitted by the owner or operator and approved by the Director. [45CSR§10-9.1.]~~

- a. Emissions from Emission Point H-101R shall not exceed the following limits:

Emission Limits for Heater H-101R		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.72	7.16
PM ₁₀	0.50	1.78
PM _{2.5}	0.50	1.78
VOC	0.12	1.19

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NO_x emissions from the heater shall not exceed 40 ppmv (dry basis, corrected to 0-percent excess air) 30-day rolling average basis. The permittee shall demonstrate compliance with this emission standard by operating this heater in a manner that the daily average O₂ in the heater's exhaust does not exceed the O₂ operating limit or O₂ operating curve ~~determined during the most recent biennial performance test as required in Condition 4.3.1. of this permit.~~

- c. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii), §60.102a(g)(2)(i)(A), §60.107a(i)(5); and 45CSR13: Permit R13-2334, 4.1.5.]

- 4.1.6. Heater H-102R is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-102R ~~for the crude distillation unit. The facility shall not burn Fuel Oil in any combustion unit, except during periods of natural gas curtailment and/or during periods of DOT required maintenance of the natural gas pipeline in which the facility shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur). Note: Fuel Oil is defined as any liquid fossil fuel with sulfur content greater than 0.05% by weight.~~

~~[45CSR13: Permit R13-2334, 4.1.4.]~~

- a. Emissions from Emission Point H-102R shall not exceed the following limits

Emission Limits for Heater H-102R		
Pollutant	Emission Limits	
	TPM	TPY

Commented [CG15]: Two options are available in NSPS Ja for compliance. Note that other sections of the permit correctly identify the two options. Recommend updating to align with other sections of the permit.

Commented [FT16R15]: The language has been added as revised in R13-2334AK.

Commented [FT17]: Since the heater is not a “fuel burning unit” as defined in 45CSR10, it is not subject to §10-3.1.5. It is subject to §10-5.1. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [CG18]: Recommend removing process unit name, which can be referenced from Table 1.

Commented [FT19R18]: “crude distillation unit” has been replaced with “CDU Vacuum Heater” as revised in R13-2334AK.

Emission Limits for Heater H-102R		
CO	0.51	5.15
NO _x	1.12	11.16
PM ₁₀	0.36	1.28
PM _{2.5}	0.36	1.28
VOC	0.12	0.86

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
 Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. ~~Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.~~

~~[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii);45CSR13: Permit R13-2334, 4.1.6.]~~

All Boilers and Heaters Except H-201

- 4.1.7. Heater H-201 is a “fuel gas combustion device” under Subpart J of 40 CFR 60; and “process heater” under Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-201 ~~for the crude distillation unit. No person shall cause, suffer, allow or permit the discharge of particulate matter into the open air in excess of the following:~~

Emission Unit	PM Emission Limit (lbs/hr)
Boiler A	14.36
Boiler B	14.36
Boiler C	8.55
Portable Boiler	8.99
H-101R	4.91
H-102R	3.53
H-500S	5.36
H-501R	1.04
H-600S	3.74
H-441	1.11
H-701	1.09
H-901	2.48
H-1101	3.49

~~[45CSR§2-4.1.b. and 45CSR13: Permit R13-2334, 4.1.6.]~~

- a. Emissions from Emission Point H-201 shall not exceed the following limits:

Emission Limits for Heater H-201		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.43	2.38
NO _x	0.28	2.78

Commented [FT20]: Since the heater is not a “fuel burning unit” as defined in 45CSR10, it is not subject to §10-3.1.5. It is subject to §10-5.1. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [CG21]: Process heater is not a defined term in NSPS J. It becomes a defined term in Ja once Ja is triggered for NO_x. This revision has also been proposed for other sections in the permit.

Commented [FT22R21]: Subpart J has been deleted

Commented [CG23]: PDR heater.

Commented [FT24R23]: “crude distillation unit” has been replaced with “PDR unit” as revised in R13-2334AK.

PM ₁₀	0.02	0.22
PM _{2.5}	0.02	0.22
VOC	0.02	0.16

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. ~~Compliance with this streamlined requirement ensures compliance with the fuel requirements and SO₂ lb/hr limit in 45CSR§10-3.1.5lb/mmBtu limit in CO-SIP-95-1 – Condition IV.7.~~

~~[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1);CO-SIP-95-1 - Condition IV.7.; 45CSR13: Permit R13-2334, 4.1.7.]~~

- 4.1.8. Heater H-441 is a “process heater” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-441 ~~for the crude distillation unit. The visible emission standards set forth in 45CSR§2-3 shall apply at all times except in periods of start-ups, shutdowns and malfunctions. Where the Director believes that start-ups and shutdowns are excessive in duration and/or frequency, the Director may require an owner or operator to provide a written report demonstrating that such frequent start-ups and shutdowns are necessary.~~
~~[45CSR§2-9.1. and 45CSR13: Permit R13-2334, 4.1.7.]~~

- a. Emissions from Emission Point H-441 shall not exceed the following limits:

Pollutant	Emission Limits for Heater H-441	
	Emission Limits	
	TPM	TPY
CO	0.44	4.44
NO _x	0.53	5.28
PM ₁₀	0.04	0.40
PM _{2.5}	0.04	0.40
VOC	0.03	0.29

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. This heater shall be limited to firing exclusively on natural gas. Therefore, this heater is exempt from the requirements of subdivision 8.1.1. and subsections 8.2 of 45CSR2; and the requirements of section 8 of 45CSR10.

~~[46CSR§2-8.4.2.; 45CSR§10-10.3.; 45CSR13: Permit R13-2334, 4.1.8.]~~

- 4.1.9. Heater H-501R is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-501R ~~for the crude distillation unit. At all times, including periods of start-ups, 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 Director which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance~~

Commented [FT25]: Since the CO SIP requirement is still applicable, it has been streamlined here as opposed to adding a separate less stringent requirement. Also the heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [CG26]: Hydrogen plant heater.

Commented [FT27R26]: “crude distillation unit” has been replaced with “Hydrogen plant” as revised in R13-2334AK.

Commented [CG28]: Unifiner charge heater.

Commented [FT29R28]: “crude distillation unit” has been replaced with “Unifier Charge Heater” as revised in R13-2334AK.

procedures and inspection of the source. Process heaters H-101R, H-102R, and H-501R shall be equipped with low-NO_x burners.

[45CSR§2-9.2., 45CSR13: Permit R13-2334, 4.1.8., 45CSR16, and 40CFR§60.11(d)]

a. Emissions from Emission Point H-501R shall not exceed the following limits:

Emission Limits for Heater H-501R		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.15	1.50
NO _x	0.33	3.27
PM ₁₀	0.04	0.38
PM _{2.5}	0.04	0.38
VOC	0.03	0.25

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); 45CSR13: Permit R13-2334, 4.1.9.]

- 4.1.10. Heaters H-502, H-503, H-504, and H-506 under H-500S are “fuel gas combustion devices” under Subpart J of 40 CFR 60; Heater H-505R under H-500S is a “fuel gas combustion device” and “process heater” under Subpart Ja of 40 CFR 60; and all the heaters under H-500S are “process heaters” under 45CSR2, and 45CSR10; The following conditions and requirements are specific to Heater H-500S *for the crude distillation unit. 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 following: the product of 3.1 and the total design heat inputs for such units discharging through those stacks in million BTU's per hour. [45CSR§10-3.1.c. (Boilers A, B, and C, Portable Boiler, Heaters H-101R, H-102R, H-441, H-501R, H-500S, H-600S, H-701, H-901, and H-1101)]*

a. Emissions from Emission Point H-500S shall not exceed the following limits:

Emission Limits for Heater H-500S		
Pollutant	Emission Limits	
	TPM	TPY
CO	2.02	20.16
NO _x	2.96	29.58
PM ₁₀	0.19	1.80
PM _{2.5}	0.19	1.76
VOC	0.13	1.31

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

Commented [FT30]: The heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [CG31]: Unifiner/Platformer unit.

Commented [FT32R31]: “crude distillation unit” has been replaced with “Unifiner/Platformer unit” as revised in R13-2334AK.

b. Heaters H-502, H-503, H-504, and H-506 shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. ~~Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5. Compliance with this streamlined requirement assures compliance with CO-SIP-1995-1 Sections IV.5.~~

c. Heater H-505R shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. ~~Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.~~

~~[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); 40 CFR §60.102a(g)(1)(ii); CO-SIP-95-1 - Condition IV.5.; and 45CSR13: Permit R13-2334, 4.1.10.]~~

- 4.1.11. ~~H-600S is a series of four (4) individual heaters venting to common emission point with all four-heaters classified as “fuel gas combustion devices” under Subpart J of 40 CFR 60; and “process heaters” under Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heaters under H-600S for the crude distillation unit. Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on a continuous twenty-four (24) hour averaging time. The owner and/or operator of a fuel burning unit shall not allow emissions to exceed the weight emissions standards for sulfur dioxide as set forth in this rule, except during one (1) continuous twenty-four (24) hour period in each calendar month and during this one (1) continuous twenty-four hour period said owner and/or operator shall not allow emissions to exceed such weight emission standards by more than ten percent (10%) without causing a violation of this rule. A continuous twenty-four (24) hour period is defined as one (1) calendar day.~~
~~[45CSR§10-3.8. and 45CSR13: Permit R13-2334, 4.1.9.]~~

a. Emissions from Emission Point H-600S shall not exceed the following limits:

Emission Limits for Heater H-600S		
Pollutant	Emission Limits	
	TPM	TPY
CO	1.50	15.01
NO _x	2.14	21.44
PM ₁₀	0.14	1.36
PM _{2.5}	0.14	1.36
VOC	0.10	0.98

~~TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.~~

b. ~~The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5. Compliance with this streamlined requirement assures compliance with CO-SIP-1995-1 Sections IV.5.~~

~~[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); CO-SIP-95-1, Condition IV.5.; 45CSR13: Permit R13-2334, 4.1.11.]~~

Commented [FT33]: Since the CO SIP requirement is still applicable, it has been streamlined here as opposed to adding a separate less stringent requirement. Also the heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [FT34]: The heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [FT35]: Subpart J has been deleted.

Commented [CG36]: ISOMAX unit.

Commented [FT37R36]: “crude distillation unit” has been replaced with “ISOMAX unit” as revised in R13-2334AK.

Commented [FT38]: Since the CO SIP requirement is still applicable, it has been streamlined here as opposed to adding a separate less stringent requirement. Also the heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Boilers A, B, and C, Heaters H-201, H-600S, H-701, H-901

- 4.1.12. Heater H-701 is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and a “process heater” under ~~Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-701 for the VFU: No owner or operator shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The listed heaters and boilers are affected facilities, as that term is used in 40 CFR Part 60 Subparts A and J. [40 CFR §60.104(a)(1) and 45CSR§16-4.1; 45CSR13: Permit R13-2334, 4.1.25.]~~

- a. Emissions from Emission Point H-701 shall not exceed the following limits:

Pollutant	Emission Limits for Heater H-701	
	Emission Limits	
	TPM	TPY
CO	0.44	4.36
NO _x	0.11	1.06
PM ₁₀	0.04	0.39
VOC	0.03	0.29

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall be fired only with natural gas and treated refinery fuel gas. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15, and 4.1.17. of this permit. ~~Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in CO-SIP-95-1 – Condition IV.6.~~

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); CO-SIP-95-1 - Condition IV.6. (SIPed); 45CSR13: Permit R13-2334, 4.1.12.]

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701, H-901

- 4.1.13. Heater H-901 is a “fuel gas combustion device” under Subpart J of 40 CFR 60; and “process heater” under ~~Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-901 for the crude distillation unit. At the request of the Director the owner and/or operator of a source shall install such stack gas monitoring devices as the Director deems necessary to determine compliance with the provisions of 45CSR10. The data from such devices shall be readily available at the source location or such other reasonable location that the Director may specify. At the request of the Director, or his or her duly authorized representative, such data shall be made available for inspection or copying. Failure to promptly provide such data shall constitute a violation of this rule. [45CSR§10-8.2.a. and 45CSR13: Permit R13-2334, 4.1.10.]~~

- a. Emissions from Emission Point H-901 shall not exceed the following limits:

Pollutant	Emission Limits for Heater H-901	
	Emission Limits	
	TPM	TPY

Commented [CG39]: The size is below 40 mmbtu/hr so NOx requirements are **not** triggered. However, this heater was not modified with respect to NOx so technically it’s not as of yet affected facility under Ja for NOx. To avoid confusion, recommend not indicating as Ja process heater. See Title V Renewal application for more details.

“H-701 and Boiler C were authorized to fire fuel gas by R13-2334O issued on March 18, 2010. Based on the modification definition the SO₂/H₂S provisions of NSPS Ja are applicable (i.e., no increase in NOX triggering modification).”

Commented [FT40R39]:

Commented [FT41R39]: Subpart J has been deleted.

Commented [FT42]: Since the CO SIP requirement is still applicable, it has been streamlined here as opposed to adding a separate less stringent requirement. Also the heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [FT43]: Subpart J has been deleted.

Commented [CG44]: DHT heater.

Commented [FT45R44]: “crude distillation unit” has been replaced with “DHT heater” as revised in R13-2334AK.

CO	0.42	4.22
NO _x	0.30	3.01
PM ₁₀	0.08	~~0.7990~~
PM _{2.5}	0.08	~~0.7990~~
VOC	0.12	1.20

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5

[45CSR`10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); 45CSR13: Permit R13-2334, 4.1.13.]

Boilers A and B

- 4.1.14. Heater H-1101 is a “indirect heat exchanger” under Subpart Dc of 40 CFR60, and a “Fuel Burning Unit” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-1101 for the hydrogen plant: The combined emissions from Boiler A and Boiler B (Emission Point ID Nos. A & B, which is a common stack) shall not exceed those listed below. NO_x limits (based on a three hour averaging period) for each boiler shall be as follows: Boiler A – 0.058 lb/MMBtu and Boiler B – 0.058 lb/MMBtu.

- a. Emissions from Emission Point H-1101 shall not exceed the following limits:

Pollutant	Emission Limits for Heater H-1101	
	Emission Limits	
	Tons per month (TPM)	Tons per year (TPY)
CO	~~0.17~~ 11.51	~~1.70~~ 115.07
NO _x	~~0.68~~ 8.1	~~6.80~~ 81.04
PM	1.04	10.42
SO ₂	0.81	8.06
PM ₁₀	0.17	1.70
PM _{2.5}	0.17	1.70
VOC	~~0.13~~ 0.75	~~1.25~~ 7.53

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

[45CSR13: Permit R13-2334, 4.1.13.]

- b. PM emissions from the Emission Point “H-1101” shall not exceed 0.47 pound per hour on a 6-hour average basis. Compliance with this streamlined PM limit will ensure compliance with 45CSR§2-4.1.2.
- c. Heater H-1101 shall not exhibit visible emissions from Emission Point “H-1101” greater than 10% on a six (6) -minute average basis.

Commented [CG46]: The previous permit limit was for filterable PM only and was not based on the AP 42 factor for both filterable and condensable. Converting the existing PM limit to PM10/PM2.5 could be problematic due to the condensable portion. Recommend aligning the PM10/PM2.5 limits with AP 42 calculation for filterable + condensable.

27.5 MMBtu/hr x 0.0075 lb/MMBtu x 8,760 hr/yr / 2,000 lb/ton.

Commented [FT47R46]: These limits are from R13-2334AK and cannot be changed without a revision to the R13 permit.

Commented [FT48]: The heater is not subject to 45CSR§10-3.1.5. and since condition 4.1.17. is the requirement from §10-5.1., Rule 10 was not streamlined here.

Commented [FT49]: Added “and a “Fuel Burning Unit” under”

d. This heater shall be limited to firing exclusively on natural gas. Therefore, this heater is exempt from the requirements of subdivision 8.1.1. and subsections 8.2 of 45CSR2; and the requirements of section 8 of 45CSR10.

e. SO₂ emissions from the Emission Point “H-1101” shall not exceed 120.8 pound per hour.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§2-8.4.2.; 45CSR§10-3.1.5.; 45CSR§10-10.3; 45CSR13: Permit R13-2334, 4.1.14.]

4.1.15. a. The permittee shall not allow any “fuel gas combustion device” (boiler or process heater) to burn any “refinery fuel gas” (RFG) that contains hydrogen sulfide (H₂S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. Emissions from the operation of Boilers A & B, shall not exceed a total emission rate of 264 lbs. SO₂/hr.
~~[CO-SIP-95-1 – Condition IV.3.B.b. (SIPed)]~~

b. For each exceedance of the 162 ppm H₂S standard in the above paragraph that results in a SO₂ discharge from a “fuel gas combustion device” subject to this standard greater than 500 pounds than the amount that would be if the H₂S emissions standard had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter. Then, the permittee shall conduct a “root cause analysis” and “corrective action analysis” as soon as possible, but no later than 45 days after such exceedance and implement “corrective action” in accordance with 40 CFR §60.103a(e) if applicable.

c. The corrective action(s) identified in the corrective action analysis conducted pursuant to 40 CFR §60.103a(d) shall be implemented in accordance with the applicable requirements in 40 CFR §60.103a(e)(1) through (3) as follows:

- i. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in 40 CFR §60.108a(c)(6)(ix).
- ii. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.
- iii. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in 40 CFR §60.108a(c)(6)(x).

[45CSR16; 40 CFR §102a(g)(1)(ii), §§60.103a(c) & (c)(2), §60.103a(d), §60.103a(e); 45CSR13: Permit R13-2334, 4.1.15.]

4.1.16. The permittee shall not allow any “fuel gas combustion device” (process heater) to burn any “fuel gas” that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 grains/dscf) determined hourly on a 3-hour rolling average basis. Any modifications or replacement of the stacks from Boilers No. A and B shall comply with the provisions of 45CSR20 “Good Engineering Practice as Applicable to Stack Heights”.

Commented [CG50]: Compliance with natural gas only requirement renders this condition unnecessary.

Calculations Basis (§45-10-3.1.5):

3.1 lb/MMBtu x 38.8 MMBtu/hr.

Commented [FT51R50]: Although H-1101 is exempt from the testing, monitoring, recordkeeping and reporting requirements of 45CSR§10-8, it is still subject to the SO₂ standard in 45CSR§10-3.1.5. and therefore will remain in the permit.

Commented [CG52]: Removing to generically apply to fuel gas combustion devices subject to Ja for future flexibility. It's possible to have a fuel gas combustion device that is not a boiler or process heater.

Commented [FT53R52]: “(boiler or process heater)” has been deleted as revised in R13-2334AK.

Commented [CG54]: Removing to generically apply to fuel gas combustion devices subject to J for future flexibility. Note that boilers are currently subject to this requirement. However, it's possible to have a fuel gas combustion device that is not a boiler or process heater.

Commented [FT55R54]: “(process heater)” has been deleted as revised in R13-2334AK.

[CO-SIP-95-1 – Condition IV.10. (SIPed)]

[45CSR`6; 40 CFR §60.104(a)(1), §60.105(e)(3)(ii); 45CSR13: Permit R13-2334, 4.1.16.]

Boiler-C

- 4.1.17. The permittee shall not combust any refinery fuel gas (refinery process gas) stream that contains hydrogen sulfide in a concentration greater than 50 grains per 100 cubic feet of gas. Compliance with this hydrogen sulfide concentration limit shall be based on 3-hour block averaging time. Boiler C shall be equipped with low NO_x burners. NO_x limits (based on a three-hour averaging period) shall be 0.050 lb/MMBTU. Emissions from Boiler C (Emission Point ID No. C) shall not exceed the limits in the following table. Compliance with the NO_x limit shall demonstrate compliance with the less stringent limit of Permit R13-2334. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.

Pollutant	Emission limit	
	Tons per month (TPM)	Tons per year (TPY)
CO	3.43	34.27
NO _x	2.08	20.81
PM	0.31	3.1
SO ₂	0.24	2.41
VOC	0.22	2.24

[45CSR13: Permit R13-2334, 4.1.14., 4.1.15.; 45CSR§10-3.1.e.]

[45CSR§§10-5.1 and 5.4.; 45CSR13: Permit R13-2334, 4.1.17.]

Heaters H-101R, H-102R, and H-501R

- 4.1.18. At all times, including periods of start-ups, shutdowns and malfunctions, the permittee shall, to the extent practicable, maintain and operate any of the permittee “fuel burning unit(s)” Boilers A, B, and C; duct burner for TDB01; and H-1101; “fuel gas combustion devices,” and “process heaters,” 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 Director and/or Administrator which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source. Process heaters H-101R, H-102R, and H-501R shall be equipped with low NO_x burners. NO_x limits (determined daily on a 30-day rolling averaging basis) on H-101R shall be 40ppmv (dry basis, corrected to 0 percent excess air). Combined emissions from H-101R and H-102R, and emissions from H-501R shall not exceed those listed below.

Pollutant	H-101R and H-102R		H-501R	
	TPM	TPY	TPM	TPY
CO	1.23	12.31	0.15	1.5
NO _x	2.67	26.68	0.33	3.27
PM _{2.5}	0.86	3.06	0.04	0.35
PM ₁₀	0.86	3.06	0.04	0.35

PM	0.86	3.06	0.04	0.38
SO ₂	1.09	10.88	0.11	1.12
VOC	0.21	2.05	0.03	0.25

[45CSR13: Permit R13-2334, 4.1.15., 4.1.16, 45CSR16, 40 CFR §60.102a(g)(2)(i)(A)]

[45CSR§2-9.2., 45CSR13: Permit R13-2334, 4.1.18., 45CSR16, and 40 CFR §60.11(d)]

Heaters H-201, H-441, and H-701

4.1.19. The conditions and requirements in the following subdivisions are specific to the Fluid Cooler (ID CCT01): Emissions from heaters H-201, H-701, and H-441 shall not exceed those listed in the following table. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.

- a. Emissions of PM, PM₁₀, and PM_{2.5} shall be controlled with a 0.001% of the recirculating water rate drift eliminator or equivalent control technology.
 - i. PM emissions emitted to the atmosphere from the Fluid Cooler shall not exceed 0.19 lb/hr and 0.82 TPY.
 - ii. PM₁₀ and PM_{2.5} emissions emitted to the atmosphere from the Fluid Cooler shall not exceed 0.01 lb/hr and 0.01 TPY.
- b. Make-up water for the Fluid Cooler shall not have a total dissolved solids concentration greater than 18,500 ppmw at any time.

Pollutant	H-201		H-701		H-441	
	TPM	TPY	TPM	TPY	TPM	TPY
CO	0.43	2.38	0.44	4.36	0.44	4.44
NO _x	0.28	2.78	0.11	1.06	0.53	5.28
PM	0.02	0.22	0.04	0.39	0.04	0.40
SO ₂	0.08	0.77	0.14	1.4	0.01	0.03
VOC	0.02	0.16	0.03	0.29	0.03	0.29

[45CSR13: Permit R13-2334, 4.1.20., 45CSR§10-3.1.e.]

[45CSR13: Permit R13-2334, 4.1.19.]

4.1.20. Heater H-441 shall be limited to combusting natural gas only.

[CO-SIP-95-1 – Condition IV.8. (SIPed); 45CSR13: Permit R13-2334, 4.1.21.]

4.1.21. The vacuum fractionator heater, H-701, shall be fired only with natural gas and/or treated refinery fuel gas that contains hydrogen sulfide in a concentration not to exceed 10 grains/100 dry standard cubic feet of gas; and emissions of sulfur dioxide shall not exceed 0.8 lbs/mmBtu.

[CO-SIP-95-1 – Condition IV.6. (SIPed)]

Heaters H-500S and H-600S

4.1.22. Emissions from H-500S and H-600S heaters shall not exceed those listed in the following table. Note: “S” means multiple heaters with emissions exiting a common emission point.

Pollutant	H-500S		H-600S	
	TPM	TPY	TPM	TPY
CO	2.02	20.16	1.5	15.01
NO _x	2.96	29.58	2.14	21.44
PM _{2.5}	0.18	1.76	n/a	n/a
PM ₁₀	0.18	1.80	n/a	n/a
PM	0.19	1.90	0.14	1.36
SO ₂	0.72	7.21	0.48	4.83
VOC	0.13	1.31	0.1	0.98

[45CSR13: Permit R13-2334, 4.1.22.]

Heaters H-901 and H-1101

4.1.23. Emissions from the DHT Heater (H-901) and Hydrogen Plant Heater (H-1101) shall not exceed those listed in the following table.

Pollutant	H-901		H-1101	
	TPM	TPY	TPM	TPY
CO	0.42	4.22	0.17	1.70
NO _x	0.30	3.01	0.68	6.80
PM	0.08	0.79	0.17	1.70
SO ₂	0.27	2.72	0.01	0.10
VOC	0.12	1.20	0.13	1.25

[45CSR13: Permit R13-2334, 4.1.23.]

4.1.24. Heater H-1101 shall be limited to combusting natural gas only.

[45CSR13: Permit R13-2334, 4.1.24.]

Boilers A, B, and C, Heaters H-201, H-500S, H-600S, H-701, and H-901

4.1.25. The permittee shall comply with the emission limitations set forth in 40 CFR 60 Subpart J on and after the date on which the initial performance test, required by 40 CFR § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

[40 CFR § 60.104, 45CSR§16-4.1; 45CSR13: Permit R13-2334, 4.1.26.]

Heaters H-101R, H-102R, H-500S, and H-501R

4.1.26. The permittee shall comply with the emission limitations set forth below on and after the date on which the initial performance test, required by 40 CFR §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

~~[45CSR16, 40 CFR §§ 60.102a (a) and (g)(1)(ii), 45CSR13: R13-2334, 4.1.17.]~~

- 4.1.27. c. Each owner or operator that operates a fuel gas combustion device subject to 40 CFR Part 60 Subpart Ja shall conduct a root cause analysis and a corrective action analysis for the following condition specified in 40 CFR §§ 60.103a (c) (2):

For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in 40 CFR § 60.102a (g) (1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

- d. A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3). Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 40 CFR §§ 60.103a (d) (1).

1. If a single continuous discharge meets any of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3) for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

5. If discharges occur that meet any of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3) for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

- e. The owner or operator of a fuel gas combustion device subject to 40 CFR Part 60 Subpart Ja shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to 40 CFR § 60.103a (d) in accordance with the applicable requirements in 40 CFR §§ 60.103a (e) (1) through (3):

1. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If permittee concludes that corrective action should not be conducted, the permittee shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in 40 CFR § 60.108a (c) (6) (ix).

2. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the permittee shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

3. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the permittee shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in 40 CFR § 60.108a (c) (6) (x).

~~j. — Alternative means of emission limitation.~~

- ~~1. — Each permittee subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in 40 CFR § 60.103a.~~
- ~~2. — Determination of equivalence to the design, equipment, work practice or operational requirements of 40 CFR § 60.103a will be evaluated by the following guidelines:~~
 - ~~i. — Each permittee applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.~~
 - ~~ii. — For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.~~
 - ~~iii. — For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.~~
 - ~~iv. — Each permittee applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.~~
 - ~~v. — The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in 40 CFR § 60.103a (j) (2) (iv).~~
 - ~~vi. — The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.~~
- ~~3. — A permittee may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.~~
- ~~4. — Approval of the application for equivalence to the design, equipment, work practice or operational requirements of 40 CFR § 60.103a will be evaluated by the following guidelines:~~
 - ~~i. — After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.~~
 - ~~ii. — After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.~~

iii. Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h) (1) of the CAA.

5. Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of 40 CFR § 60.103a. The Administrator will make an equivalence determination according to the provisions of 40 CFR §§ 60.103a (j) (2) through (4).

[45CSR16, 40 CFR § 60.103a(e)(2), (d)(1), (d)(5), (e), and (j), 45CSR13: R13-2334, 4.1.18.]

Portable Boiler

4.1.20. 4.1.28. Emissions from the Portable Boiler shall not exceed the following:

CO		NO _x		PM		SO ₂		VOCs		HAPs	
lb/hr	tpy	lb/hr	tpy	lb/hr*	tpy	lb/hr*	tpy	lb/hr	tpy	lb/hr	tpy
8.23	11.06	4.90	6.58	0.74	1.00	0.06	0.08	0.54	0.72	0.01	0.02

* Compliance with these streamlined PM and SO₂ lb/hr limits will ensure compliance with 45CSR§2-4.1.2. and 45CSR§10-3.1.5. respectively.

[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13: R13-2334, 4.1.3.a, 4.1.27.]

4.1.21. 4.1.29. The portable boiler shall burn pipeline quality natural gas only.

[45CSR13: R13-2334, 4.1.3.b, 4.1.28.]

4.1.22. 4.1.30. The portable boiler shall only operate at the following times:

- When either Boilers A, B or C are offline; or
- Prior to the shutdown of Boiler A, B, or C only while the portable boiler is in startup mode; or
- When Boiler A, B, or C is in startup mode.

[45CSR13: R13-2334, 4.1.3.c, 4.1.29.]

4.1.23. 4.1.31. The portable boiler shall not operate more than 2,688 hours per year. Compliance with this condition shall be based on a 12 month rolling total.

[45CSR13: R13-2334, 4.1.3.d, 4.1.30.]

4.1.24. 4.1.32. The portable boiler shall not be attached to a foundation and shall not be onsite for more than 180 consecutive days.

[45CSR13: R13-2334, 4.1.3.e, 4.1.31.]

4.1.25. 180 days after the initial startup of TBD01 (combustion turbine w/duct burner), the permittee shall not longer be authorized to bring on site and operate a portable boiler under this permit.

[45CSR13: R13-2334, 4.1.3.f.]

Commented [FT56]: Previously corrected

Commented [FT57]: Previously corrected

4.2. Monitoring Requirements

All Boilers and Heaters

4.2.1. ~~For the purpose of verifying compliance for the boilers and heaters, which has been identified in Section 4.1, that is subject to the opacity limits of 45CSR2-3.1, the permittee shall conduct visible emission checks and/or opacity monitoring and recordkeeping in accordance with the following. Visual emission checks of each emission point subject to an opacity limit shall be conducted during periods of facility operation for a sufficient time interval to determine if the unit has visible emissions using 40 CFR 60 Appendix A, Method 22. If natural gas is being combusted, the visual emissions checks shall be conducted monthly. If fuel oil is being combusted, the visual emissions checks shall be conducted weekly. If visible emissions are identified during the survey, or at any other time, the permittee shall take corrective action to minimize the emissions immediately. If during these checks, or at any other time, visible emissions are observed, a visible emission evaluation shall be conducted in accordance with 40 CFR 60 Appendix A, Method 9. A Method 9 evaluation shall not be required if the visible emission condition is corrected in a timely manner. A record of each visible emission check required above shall be maintained on site for a period of no less than five (5) years. Said record shall include, but not be limited to, the date, time, name of emission unit, the applicable visible emissions requirement, the results of the check, what action(s), if any, was/were taken, the name of the observer, and any data required by 40 CFR 60 Appendix A, Method 22 or Method 9.~~

a. ~~The visible emission check shall determine the presence or absence of visible emissions. 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 Part 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR Part 60, Appendix A, Method 9 certification course.~~

b. ~~Visible emission checks shall be conducted at least once per calendar year of the respective emission point for Boilers A, B, and C; and Heater ~~H-600~~ H-1101. These checks shall be performed at each source (stack, transfer point, fugitive emission source, etc.) for a sufficient time interval, but no less than six (6) minutes, to determine if any visible emissions are present. Visible emission checks shall be performed during periods of normal facility operation and appropriate weather conditions.~~

c. ~~If visible emissions are present at a source(s) during the visible emission check, the permittee shall conduct an opacity reading at that source(s) using the procedures and requirements of U.S. EPA Method 9 as soon as practicable, but within seventy-two (72) hours of the visual emission check that detected visible emissions. Records of such checks and Method 9 observations shall be maintained in accordance with Condition 3.4.2 of this permit.~~

[45CSR13:- Permit R13-2334, 4.2.1.]

~~Boilers A and B, All Heaters (except H-101R, H-102R, H-501R, H-901 and H-1101)~~

4.2.2. ~~For Boilers A and B, All Heaters (except H-101R, H-102R, H-501R, H-901 and H-1101):~~ Compliance with the emission limitations of CO-SIP-95-1 shall be based upon the averaging time and compliance determination methods established within ~~Section V of CO-SIP-95-1 in Sections 4.2.4. through 4.2.7., and 4.2.10. of this permit.~~

[CO-SIP-95-1 - Condition V.1. (SIPed)]

Commented [CG58]: Only units subject to Rule 2 require the visual checks.

Commented [FT59R58]: H-600 has been removed as revised in R13-2334AK.

Boilers A and B

- 4.2.3. For Boilers A and B: The permittee shall monitor compliance with 45CSR§2-3 in an approved monitoring plan (see Appendix A) for each emission unit. Such plans shall include, but not be limited to, one or more of the following: continuous measurement of emissions, monitoring of emission control equipment, periodic parametric monitoring, or such other monitoring as approved by the Director.
~~[45CSR§2-8.2.; 45CSR13; Permit R13-2334, 4.1.12.]~~
- 4.2.4. The permittee shall monitor O₂ of the exhaust from Heater H-101R as alternative to monitoring NO_x emissions as allowed under Subpart Ja of 40 CFR60 for natural draft process heater with a heat input between 40 to 100 MMBtu/hr in accordance with the following requirements for the purpose of demonstrating compliance with Condition 4.1.5.b. of this permit: ~~Compliance with the sulfur dioxide emission limitations established in Section 4.1.15. for gas-fired boiler Nos. A and B shall be demonstrated in accordance with the following provisions:~~
- a. The permittee shall install, operate, and maintain O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.
 - b. The permittee shall conduct performance evaluations of each O₂ monitor according to the requirements in 40 CFR §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to 40 CFR60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.
 - c. The permittee shall comply with the quality assurance requirements in Procedure 1 of appendix F to 40 CFR60 for each O₂ monitor, including annual accuracy determinations for O₂ monitors, and daily calibration drift tests.
 - d. For Heater H-101R, the permittee shall determine excess NO_x emissions as each day during which the concentration of O₂ as measured by the O₂ continuous monitoring system required under this condition exceeds the O₂ operating limit or operating curve determined during the most recent biennial performance test as required in Condition 4.3.1 of this permit.
 - e. The permittee shall maintain records of the measured readings, performance evaluations, annual accuracy determinations, daily calibration drift tests and any maintenance performed on the monitoring system/instrument in accordance with Condition 3.4.2. of this permit.
- ~~a.—Co-located continuous monitoring systems (for sulfur dioxide and oxygen) shall be installed, calibrated, maintained and operated to measure the concentration of sulfur dioxide and oxygen in the combustion gases discharged from these boilers.—The continuous monitoring systems and programs shall comply with the requirements of Sections 4.2.5. and 4.2.6.~~
- ~~b.—Following installation of the continuous monitoring system, compliance shall be determined based upon a rolling three (3) hour average of measured sulfur dioxide concentrations and procedures approved by the Director to calculate hourly mass emissions.~~

e.—During any period after June 1, 1995 in which either of these boilers is operated without its continuous emission monitoring system in proper operation, the Company shall fire only natural gas or desulfurized refinery fuel gas in the boiler.

**[CO-SIP-95-1 – Condition V.3. (SIPed) (During fuel oil combustion only, see Section 4.1.6.)]
[\[45CSR16; 40 CFR §§60.107a\(c\), \(c\)\(3\) – \(c\)\(5\) and \(i\)\(5\); 45CSR13: Permit R13-2334, 4.2.4.\]](#)**

4.2.5.—Installation, calibration, maintenance and operation of the continuous emission monitoring systems required under Section 4.2.4., shall comply with the following provisions under 40 CFR Part 60:

a. Part 60.13(a)	i. Part 60.13(j)
b. Part 60.13(e)	j. Part 60.45(e)
c. Part 60.13(d)(1) ———	k. Part 60.45(e)
d. Part 60.13(e)(2)	l. Part 60.45(f)
e. Part 60.13(f) —	m. Part 60.46(b)(4)
f. Part 60.13(g)	n. Part 60; Appendix A, Methods 6, 6A and 6B
g. Part 60.13(h)	o. Part 60; Appendix B, Performance Specification 2
h. Part 60.13(i) —	p. Part 60; Appendix B, Performance Specification 3

Where the term “Administrator” (USEPA) is used within any of the adopted 40 CFR Part 60 provisions, the term shall mean the Director.

[CO-SIP-95-1 – Condition V.5. (SIPed)]

4.2.6.—All continuous emission monitoring data required to be collected under Section 4.2.4. shall be quality assured in accordance with 40CFR part 60, Appendix F Quality Assurance Procedures.

[CO-SIP-95-1 – Condition V.7. (SIPed)]

Boilers A and B, Heaters H-701, H-500S, H-600S

[4.2.5.](#) ~~4.2.7.~~ Sources of sulfur dioxide emissions subject to CO-SIP-95-1 shall demonstrate compliance with the emission standards set forth in [subsections IV .3, IV .4 , IV .5, IV .6, IV .7, IV .9 and IV .10 of CO-SIP-95-1](#) Sections ~~4.1.15., 4.1.21., and 5.1.5.~~, using data collected in accordance with ~~this section V. of CO-SIP-95-1~~ and reference emissions test procedures in 40 CFR Part 60, Appendix A, Methods 6, 6A, 6B, and 19.

[CO-SIP-95-1 - Condition V.8. (SIPed)]

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701, H-901

[4.2.8.](#)—The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) shall demonstrate compliance with sections 3, 4 and 5 of 45CSR10 by testing and /or monitoring in accordance with one or more of the following: 40 CFR Part 60, Appendix A, Method 6, Method 15, continuous emissions monitoring systems (CEMS) or fuel sampling and analysis as set forth in an approved monitoring plan for each emission unit (see Appendix A).

[45CSR§10-8.2.c.; 45CSR13: Permit R13-2334, 4.1.11.]

Boilers A, B, and C, Heaters H-201, H-600S, H-701, H-901

[4.2.6.](#) ~~4.2.9.~~ To demonstrate compliance with Conditions 4.1.15., 4.1.16., and 4.1.17., the permittee shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration

by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

~~To demonstrate compliance with Section 4.1.12, the permittee shall install, certify, calibrate, maintain, and operate a fuel gas CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B.~~

- a. ~~This instrument shall be installed, operated, and maintained according to Performance Specification 7 to 40 CFR60. The span value for this instrument is 300 ppmv H₂S. Compliance with this streamlined span value of 300 ppmv H₂S will ensure compliance with 40 CFR §105(a)(4)(i).~~

~~During any period of failure or malfunction of the H₂S monitor system, the permittee shall collect two (2) gas samples of the RFG per eight (8) hour period and determine the H₂S concentration and heating value of each sample through a gas chromatography in accordance with ASTM Method D-1945. The permittee may request approval by the Director of alternative sampling and analytical methods for determination of these parameters during periods when the H₂S monitoring system has failed or malfunctioned.~~

- b. ~~The permittee shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR§60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to 40 CFR60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR§60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to 40 CFR60.~~

- c. ~~The permittee shall comply with the applicable quality assurance procedures in appendix F to 40 CFR60 for each H₂S monitor.~~

- d. ~~Fuel gas combustion devices or flares 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 fuel gas combustion devices or flares.~~

- e. ~~For the duct burner for the combustion turbine; Boiler C and Heaters H-101R, H-102R, H-501R, H-505R, and H-701, the permittee shall determine excess the arithmetic average of each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under this condition exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under this condition exceeds 60 ppmv.~~

- f. ~~For Boiler A, Boiler B, Heaters H-201, H-500S (excluding H-505R), H-600S and H-901, the permittee shall determine excess the arithmetic average of all three (3) hour averages during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under this condition exceeds 230 mg/dscm (0.10 gr/dscf).~~

- g. ~~For Boilers A, B, and C; duct burner for the combustion turbine; and Heaters H-101R, H-102R, H-201, H-501R, H-500S, H-600S, H-701, and H-901, the permittee shall determine each 3-hour block average exceeds 50 grains per 100 scf of gas if there are excess emission identified from paragraphs e. (3-hour standard) or f. of this condition.~~

Commented [FT60]: Added "Boiler A and Boiler B and the H-500S (excluding H-505R) as revised in R13-2334AK

Commented [FT61]: Added a comma.

- h. ~~For any periods that the excess emissions are determined of the short term (3-hour average) average standards under paragraphs e. and/or f. of this condition, the permittee shall determine the daily SO₂ emissions in terms of lb of SO₂ per hour for Boilers A and B, and lb of SO₂ per MMBtu for Heater H-201, H-500S, H-600S, and H-701 to determine compliance the SO₂ limits of Consent Order CO-SIP-95-1.~~

~~All valid hourly reading shall be in reduce into 3-hour averages. Records of all readings, maintenance preformed, calibrations, and audits shall be maintained in accordance with Condition 3.4.2. of this permit.~~

~~Compliance with the hydrogen-sulfide concentration limit of permit condition 4.1.12. shall be demonstrated using the continuous monitor as follows:~~

- a. ~~An instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.~~
- i. ~~The span value for this instrument is 425 mg/dscm H₂S.~~
- ii. ~~Fuel gas combustion devices 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.~~
- iii. ~~The performance evaluations for this H₂S monitor under 40 CFR § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations~~

~~Compliance with [this condition will ensure](#) shall demonstrate compliance with CO-SIP-95-1, Conditions V.3., V.4., V.5., and V.6.~~

~~[45CSR16; 40 CFR §§60.7(f), (f)(1) and (f)(2), §60.105(a)(4)(i), (ii), and (iii), 105(e)(3)(ii), §§107a(a)(2)(i)-(iv), §107a(i)(1)(ii); and 45CSR§16-4.1; 45CSR§10-5.4. and §§10-8.2.3., 8.2.3.a., 8.2.3.a.1.; CO-SIP-95-1 - Conditions V.3. V.4., V.5., V.6., V7 and V.11. (SIPed); 45CSR13: Permit R13-2334, 4.2.2., 4.2.4.]~~

Heaters H-201, H-500S, H-600S

~~4.2.10.—Compliance with the sulfur dioxide emission limitations established in Sections 4.4.12. and 4.4.14. for Process Heater H-201, H-500S, and H-600S shall be determined daily in accordance with the following provisions:~~

- a. ~~Total daily sulfur dioxide emissions for each heater shall be calculated by adding the sulfur dioxide emissions attributable to each fuel fired during all twenty-four (24) hour periods.~~
- b. ~~Sulfur dioxide emissions attributable to the combustion of fuel oil shall be determined by sampling and analyzing the volume of fuel oil fired for sulfur content and heating volume in accordance with applicable ASTM sampling and analytical methods and accurately measuring the volume and mass of fuel oil fired in each heater.~~

~~[CO-SIP-95-1 – Condition V.4. (SIPed) (During fuel oil combustion only, see Section 4.1.6.)]~~

Heaters H-901 and H-1101

~~4.2.7.~~ ~~4.2.11.~~ The permittee shall monitor and record the amount of fuel gas consumed in Heaters H-101R, H-102R, H-201, H-501R, H-500S, H-600S, H-701, H-901 and duct burner for TDB01 through individual volumetric flow meters. Records of the readings, maintenance performed on the instruments, and calibrations shall be maintained in accordance with Condition 3.4.2. of this permit. ~~using flow meters.~~

[45CSR13: Permit R13-2334, 4.2.6.; CO-SIP-95-1 - Condition V.4. (SIPed)]

~~4.2.8.~~ ~~4.2.12.~~ The permittee shall monitor and record the amount of natural gas consumed in heaters H-441 and H-1101 using flow meters. Records of the readings, maintenance performed on the instruments, and calibrations of the instruments shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR13: Permit R13-2334, 4.2.5.]

Boilers A and B

~~4.2.9.~~ ~~4.2.13.~~ To demonstrate compliance with the three-hour average NO_x limit of Section ~~4.1.1.b.~~ ~~4.1.14.~~, the permittee shall install, certify, calibrate, maintain, and operate a CEMS on Boilers A and B to measure NO_x and O₂ in accordance with the requirements of 40 CFR §§60.11, 60.13, and 40 CFR Part 60 Appendices A and F.

[45CSR13: Permit R13-2334, 4.2.3.]

Heaters H-101R, H-102R, H-500S, and H-501R

~~4.2.14. a. — Fuel gas combustion devices subject to H₂S limit.~~

~~The owner or operator of a fuel gas combustion device that is subject to 40 CFR § 60.102a(g)(1) and elects to comply with the H₂S concentration limits in 40 CFR § 60.102a(g)(1)(ii) shall comply with 40 CFR § 60.107a(a)(2).~~

~~2. — The owner or operator of a fuel gas combustion device that elects to comply with the H₂S concentration limits in 40 CFR § 60.102a(g)(1)(ii) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device.~~

~~i. — The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of 40 CFR Part 60 Appendix B. The span value for this instrument is 300 ppmv H₂S.~~

~~ii. — The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR § 60.13 (c) and Performance Specification 7 of 40 CFR Part 60 Appendix B. The owner or operator shall use Method 11, 15, or 15A of 40 CFR Part 60 Appendix A-5 or Method 16 of 40 CFR Part 60 Appendix A-6 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA Method 15A of 40 CFR Part 60 Appendix A-5.~~

~~iii. — The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR Part 60 Appendix F 60 for each H₂S monitor.~~

- iv. Fuel gas combustion devices 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 fuel gas combustion devices.

d. *Process heaters complying with the NO_x heating value-based or mass-based limit.*

The owner or operator of a process heater subject to the NO_x emissions limit in 40 CFR § 60.102a (g) (2) and electing to comply with the applicable emissions limit in 40 CFR § 60.102a (g)(2)(i)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in 40 CFR §§ 60.107a (d)(1) through (4).

1. Except as provided in 40 CFR § 60.107a (d)(8), the owner or operator shall install, operate and maintain each NO_x monitor according to the requirements in 40 CFR §§ 60.107a (c) (1) through (5). The monitor must include an O₂ monitor for correcting the data for excess air.
2. Except as provided in 40 CFR § 60.107a (d)(3), the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of Appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).
3. As an alternative to the requirements in 40 CFR § 60.107a (d)(2), the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of 40 CFR Part 60 Subpart Ja and Equation 10 of 40 CFR § 60.107a. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1,000,000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)}$$

Where:

- F_d = F factor on dry basis at 0 percent excess air, dscf/MMBtu.
X_i = mole or volume fraction of each component in the fuel gas.
MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).
MHC_i = molar heat content, Btu per mole (Btu/mol).
1,000,000 = unit conversion, Btu per MMBtu.

4. The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of 40 CFR Part 60 Appendix B. Any of the following methods shall be used for conducting the relative accuracy evaluations:
 - i. EPA Method 18 of 40 CFR Appendix A-6;
 - ii. ASTM D1945-03 (Reapproved 2010) (incorporated by reference see 40 CFR § 60.17);
 - iii. ASTM D1946-90 (Reapproved 2006) (incorporated by reference see 40 CFR § 60.17);

- iv. —ASTM D6420-99 (Reapproved 2004) (incorporated by reference see 40 CFR § 60.17);
- v. —GPA 2261-00 (incorporated by reference see 40 CFR § 60.17); or
- vi. —ASTM UOP539-97 (incorporated by reference see 40 CFR § 60.17).

i. *Excess emissions:*

For the purpose of reports required by § 40 CFR § 60.7 (c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in 40 CFR § 60.102a (g) are defined as specified in 40 CFR §§ 60.107a (i) (1) through (5). Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (e.g., a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

1. H₂S limits for fuel gas combustion devices. ii. If the owner or operator of a fuel gas combustion device elects to comply with the H₂S concentration limits in 40 CFR § 60.107a § 60.102a (g) (1) (ii), each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under 40 CFR § 60.107a (a) (2) exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under 40 CFR § 60.107a (a) (2) exceeds 60 ppmv.

3. Rolling 30-day average NO_x limits for fuel gas combustion devices. Each rolling 30-day period during which the average concentration of NO_x as measured by the NO_x continuous monitoring system required under 40 CFR § 60.107a (c) or (d):

- i. —For a natural draft process heater, 40 ppmv and, if monitored according to 40 CFR § 60.107a (d), 0.040 lb/MMBtu;

[45CSR16, 40 CFR §§ 60.107a(a)(2)(i) through (iv), (d)(1) through (4), (i)(1)(ii), and (i)(3)(i), 45CSR13: R13-2334, 4.2.7.]

Portable Boiler

- 4.2.10. 4.2.15. To demonstrate compliance with the requirements of 4.1.23, 4.1.31, the permittee shall monitor the number of hours of operation of the Portable Boiler on a monthly basis.
[45CSR13: R13-2334, 4.2.7, 4.2.8.]

- 4.2.11. To demonstrate compliance with the NO_x emission limits of Conditions 4.1.4.a.i. and 4.1.4.f., the permittee shall install, certify, calibrate, maintain, and operate a CEMS to determine NO_x emissions from the combustion turbine with duct burner accordance with the following requirements.

- a. Each NO_x diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. Alternatively, a NO_x diluent CEMS that is installed and certified according to appendix A of 40 CF 75 is acceptable for use under 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 for each type of fuel shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to 40 CFR 75 are acceptable for use under this condition.
- 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. For the determination of mass NO_x emissions, the permittee shall install, calibrate, maintain, and operate according to manufacturer's written instructions a flow meter measuring the exhaust flow from emission point TDB01.
- f. The permittee shall develop and keep on-site a quality assurance (QA) plan for all the continuous monitoring equipment described in this condition. For the CEMS and fuel flow meters, the permittee may, with Director's 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.
- g. Records of readings, calibrations, performance evaluations, quality assurance tests/checks, and maintenance performed shall be maintained in accordance with Condition 3.4.2.

[45CSR16; 40 CFR §60.7(f), §§60.4333(b) & (b)(1), §60.4345; 45CSR13: R13-2334, 4.2.8.]

4.2.12. To demonstrate compliance with the SO₂ emission standard of Condition 4.1.4.a.ii., the permittee shall sample and analyze the refinery fuel gas each operating day that refinery fuel gas is combusted by duct burner associated with TDB01.

- a. A representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see 40 CFR §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see 40 CFR§60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see 40 CFR §60.17).
- b. The fuel analysis required in this condition may be performed either by the permittee, or a service contractor retained by permittee. The collected samples shall be analyze to determine the total sulfur content of the refinery fuel gas using: ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17).

If the permittee satisfies the criteria under 40 CFR §60.4370(c), the permittee may switch from the daily operating day sampling schedule, as required in this condition, to one of the two "custom schedules" as prescribed in 40 CFR §60.4370(c).

Records of the analyses, to include the date/time when the sample was taken and analyzed and chain of custody of the sample shall be maintained in accordance with Condition 3.4.2. of this permit.

Excess SO₂ emissions are for each operating hour that the duct burner is combusting refinery fuel gas in the period beginning on the date and hour of any sample for which the sulfur content of the refinery fuel gas exceeds the applicable limit in Condition 4.1.4.a.ii. and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

As an alternative to the above monitor requirements, the permittee may elect to utilize the daily average H₂S concentration readings of the refinery fuel gas from the H₂S monitor as required in Condition 4.2.6.e. and convert the daily average H₂S concentration into the form of the SO₂ emission standard stated in Condition 4.1.4.a.ii. ~~For the purposes of the conversion, the permittee shall assume a ratio of 1:1 for H₂S to total sulfur. The permittee shall determine excess SO₂ emissions as outline in 40CFR§60.4385 for each reporting period (if any) and report such excess SO₂ emissions in accordance with 40CFR§60.4375(a) and Condition 3.5.3.~~

Commented [FT62]: This addition was not included in R13-2334AK and therefore will not be added to the title V permit.

~~[45CSR16; 40 CFR §60.7(f), §60.4373(b), §60.4370(c), §4385(a), §60.13(i) and Approval Letter of Ergon-West Virginia Inc. Request for Regulatory Applicability Determination: Exemption from NSPS KKKK SO₂ Limits for Sources Subject to NSPS Ja, Dated April 21, 2025; 45CSR13: R13-2334, 4.2.9.]~~

- 4.2.13. For determining compliance with this emission limit in Condition 4.1.19., the permittee shall monitor cooling water flow rate continuously and the concentration of total dissolved solids contained in the make-up water of the fluid cooler or specific conductivity on a daily basis when the fluid cooler is operating. If the permittee uses a correlation curve or ratio between total dissolve solids concentration and specific conductivity, the Director or his/her representative may request the permittee verify the correlation at any reasonable time with just cause. The permittee shall determine the PM, PM₁₀, and PM_{2.5} emissions from the fluid cooler using a method that accurately predicts these specific pollutants from the fluid cooler. Such determination shall be conducted monthly. Records of such monitoring and determinations shall be maintained in accordance with Condition 3.4.2. of this permit.
~~[45CSR13: R13-2334, 4.2.10.]~~

4.3. Testing Requirements

~~Heaters H-101R, H-102R, H-500S, and H-501R~~

- 4.3.1. The permittee shall conduct biennial (once every 2 years) performance tests according to the requirements in 40 CFR §60.104a(i), establish a maximum excess O₂ operating limit or operating curve ~~according for Heater H-101R according to the requirements in §60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of 40 CFR §60.107a to demonstrate compliance. If an O₂ operating curve is used (i.e., if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of 40 CFR §60.107a, respectively.~~

Commented [FT63]: This typo has been corrected.

- a. ~~i.~~—The permittee shall determine compliance with the NO_x emissions limits in 40 CFR §60.102a (g) for a fuel gas combustion device according to the following test methods and procedures:

- ~~1.—40 CFR Part 60 Appendix A-1, Method 1 for sample and velocity traverses;~~
- ~~2.—40 CFR Part 60 Appendix A-1, Method 2 for velocity and volumetric flow rate;~~

3. ~~40 CFR Part 60 Appendix A-2, Method 3, 3A, or 3B for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-2, Method 3B;~~

5. ~~40 CFR Part 60 Appendix A-4, Method 7, 7A, 7C, 7D, or 7E for moisture content and for the concentration of NO_x calculated as NO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-41, Method 7 or 7C;~~

1. For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in 40 CFR §§60.107a(c)(6) or (d)(8), the owner or operator shall establish the O₂ operating limit or O₂ operating curve based on the performance test results according to the requirements in 40 CFR §§60.104a(i)(6)(i) or (ii), respectively.

i If a single O₂ operating limit will be used:

A. Conduct the performance test following the methods provided in 40 CFR §§60.104a(i)(1), (2), (3) and (5) when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

B. Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

C. Determine the average O₂ concentration for each test run of a valid test.

D. Calculate the O₂ operating limit as the average O₂ concentration of the three test runs from a valid test.

ii If an O₂ operating curve will be used:

A. Conduct a performance test following the methods provided in 40 CFR §§60.104a(i)(1), (2), (3) and (5) at a representative condition for each operating range for which different O₂ operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired, primarily oil fired, and equally co-fired, i.e., approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

B. Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs.

If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

- C. If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (i.e., when the process heater is firing at 50 percent or less of the rated heat capacity). If O₂ operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.
 - D. Determine the average O₂ concentration for each test run of a valid test.
 - E. Calculate the O₂ operating limit for each operating range as the average O₂ concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.
 - F. Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O₂ operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O₂ operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.
 - G. Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.
2. The owner or operator of a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O₂ limit, as provided in 40 CFR §§60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in §60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.
3. The owner or operator shall use Equation 8 of 40 CFR §60.104a to adjust pollutant concentrations to 0-percent O₂ or 0- percent excess air.
- b. ~~1.~~ The permittee shall determine compliance with the applicable H₂S emissions limit in 40 CFR §60.102a (g)(1) for a fuel gas combustion device according to the following test methods and procedures:
- 1. ~~40 CFR Part 60 Appendix A-1, Method 1 for sample and velocity traverses;~~
 - 2. ~~40 CFR Part 60 Appendix A-1, Method 2 for velocity and volumetric flow rate;~~

Commented [CG64]: Consider changing this section to 4.3.2, and renumbering subsequent sections. H₂S test procedures should be separate and distinct from NO_x stack testing and O₂ monitoring.

Commented [FT65R64]: Changed to 4.3.2, and renumbered subsequent conditions as requested.

~~3. 40 CFR Part 60 Appendix A-2, Method 3, 3A, or 3B for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-2, Method 3B;~~

1. ~~4.~~ 40 CFR Part 60 Appendix A-5, Method 11, 15, or 15A or 40 CFR Part 60 Appendix A-6, Method 16 for determining the H₂S concentration for affected plants using an H₂S monitor as specified in 40 CFR §60.107a (a) (2). The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-5, Method 15A. The permittee may demonstrate compliance based on the mixture used in the fuel gas combustion device or for each individual fuel gas stream used in the fuel gas combustion device.

- i For 40 CFR Part 60 Appendix A-5, Method 11, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H₂S may necessitate sampling for longer periods of time.
- ii For 40 CFR Part 60 Appendix A-5, Method 15, at least three injects over a 1-hour period constitutes a run.
- iii For 40 CFR Part 60 Appendix A-5, Method 15A, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-5, Method 15A.
- iv If monitoring is conducted at a single point in a common source of fuel gas as allowed under 40 CFR §60.107a (a) (2) (iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

[45CSR16, 40 CFR §§~~60.104a(i)(6), (i)(7), (i)(8)~~ and (j), ~~§60.107(c)(6)~~; 45CSR13, R13-2334, ~~4.1.19, and 4.3.1.~~]

Boilers A and B, Heaters H-201, H-701, H-500S, H-600S

- 4.3.2. For Boilers A and B, Heaters H-201, H-701, H-500S, H-600S: Any source for which compliance with sulfur dioxide emissions limitations are not demonstrated using continuous emission monitoring systems, must demonstrate compliance in accordance with Section 4.2.5, 4.2.7, not less frequently than semi-annually. At least three test runs, each with sufficient samples to characterize a two-hour period representative of normal source operation, shall be required for each compliance demonstration using the reference test procedures specified in Section 4.2.5, 4.2.7. The Director may order any person subject to CO-SIP-95-1 to conduct or have conducted an emissions test at any time that he or she has reason to believe that an emission limitation may be exceeded. The semi-annual tests shall otherwise be scheduled as ordered by or in consultation with the Director. No tests shall be required for units burning only natural gas.

[CO-SIP-95-1 - Condition V.9. (SIPed)]

Boilers A, B, and C, Heaters H-201, H-701, H-500S, H-600S, H-901

- 4.3.3. ~~The permittee shall conduct an initial performance test within 60 days after achieving the maximum production rate at which the TDB01 will be operated, but not later than 180 days after the initial startup of TDB01 and subsequent performance test on an annual basis (no more than 14 calendar months following the previous performance) for demonstrating compliance with the NO_x standard in Condition 4.1.4.a.i. in accordance with the 40 CFR §§60.4400(a) and the requirements of Condition 3.3.1. During any period of failure or malfunction of the hydrogen sulfide continuous emission monitoring system required under Section 4.2.9., H₂S concentrations of the refinery fuel gas shall be determined by collection of not less than two (2) gas samples per eight (8) hour period which are analyzed by gas chromatography for hydrogen sulfide content, density and heating value in accordance with ASTM Method D-1945. The Company may request approval by the Director of alternative sampling and analytical methods for determination of these parameters during periods when the H₂S monitoring system has failed or malfunctioned.~~

- a. There are two general methodologies that you may use to conduct the performance tests. For each test run:

1. Measure the NO_x concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of 40 CFR Part 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 of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_x emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_x) * Q_{std}}{P} \quad (\text{Equation 5 of 40 CFR 60, Subpart KKKK})$$

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 § 60.4350(f)(2); or

2. Measure the NO_x and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. 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 this part to calculate the NO_x emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_x emission rate in lb/MWh.
- b. 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

Commented [CG66]: Only an initial performance test is required if CEMS are installed. Subsequent annual performance test is not required for TBD01.

“you must conduct performance tests annually following the initial performance test in order to demonstrate compliance. Alternatively, you may choose to demonstrate continuous compliance with the use of a continuous emission monitoring system (CEMS) or parametric monitoring; if you choose this option, you are not required to conduct subsequent annual performance tests. “ [F. How do I demonstrate compliance?] 71 FR 38482
[Published Document: 06-5945 (71 FR 38482)]

Commented [FT67R66]: The subsequent performance test language has been deleted since 40 CFR 60 Subpart KKKK allows for CEMS to be used as an alternative to the subsequent testing.

documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

- c. Notwithstanding paragraph b. of this section (i.e., 40 CRR §60.4400(a)(2)), you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of 40 CFR Part 60 if the conditions in 40 CFR §60.4400(a)(3) are met:
- d. 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.
- e. NO_x emissions must be measured after the duct burner. The duct burner must be in operation during the performance test.
- f. Compliance with the applicable emission limit in Condition 4.1.4.a.i. 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.
- g. The permittee may elect to conduct the performance evaluation of the NO_x CEMS as part of the initial performance test (as described in 40 CFR §60.4405) for TDB01 or separately.
- h. The ambient temperature must be greater than 0 °F during the performance test.
- i. Records of such testing shall be maintained in accordance with Condition 3.4.2.

[45CSR16; 40 CFR §60.7(f), §60.8, §§60.4400(a), (b), (b)(2), (b)(4) –(b)(6); 45CSR13, R13-2334, 4.3.2, CO-SIP-95-1 – Condition V.11. (SIPed) (During fuel oil combustion only)]

- 4.3.4. The permittee shall conduct an initial performance test within 60 days after achieving the maximum production rate at which the TDB01 will be operated, but not later than 180 days after initial startup of TDB01 and subsequent performance test on an annual basis (no more than 14 calendar months following the previous performance) for demonstrating compliance with the SO₂ standard in Condition 4.1.4.a.ii. for each type of gaseous fuel combusted by TDB01 using one of the compliance options in sub-paragraphs a. through d. of this condition. Any fuel combusted by this turbine and subject to the emission standards in 40 CFR §60.102a(g)(1)(ii) is exempt from the testing requirements in this condition.

- a. 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. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR part 75 may be used;
- b. Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see §60.17). The fuel analysis of this section may be performed either by the permittee or a service contractor retained by the permittee. Analyze the samples for the total sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17);

Commented [FT68]: Added.

- c. [Measure the SO₂ concentration \(in parts per million \(ppm\)\), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers \(ASME\) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide \(incorporated by reference, see §60.17\) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of 40 CFR Part 60, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO₂ emission rate:](#)

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad (\text{Equation 6 of 40 CFR 60, Subpart KKKK})$$

[Where:](#)

- [E = SO₂ emission rate, in lb/MWh](#)
[1.664 × 10⁻⁷ = conversion constant, in lb/dscf-ppm](#)
[\(SO₂\)_c = average SO₂ 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 §60.4350\(f\)\(2\); or](#)

- d. [Measure the SO₂ and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of 40 CFR Part 60. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 \(incorporated by reference, see §60.17\). 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 Part 60 to calculate the SO₂ emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350\(f\) to calculate the SO₂ emission rate in lb/MWh.](#)

[These tests shall be conducted in accordance with Condition 3.3.1. of this permit. The report for each performance test shall be maintained in accordance with Condition 3.4.2. of this permit.](#)

[\[45CSR16; 40 CFR §60.7\(f\), §60.8, §60.4415 and Approval Letter of Ergon-West Virginia Inc. Request for Regulatory Applicability Determination: Exemption from NSPS KKKK SO₂ Limits for Sources Subject to NSPS Ja, Dated April 21, 2025; 45CSR13, R13-2334, 4.3.3.\]](#)

- 4.3.5. Within 12 months after initial startup with no less than 2 months of actual operation of the HRSG producing steam for the facility, the permittee shall conduct a performance test to demonstration compliance with the mass CO, formaldehyde, and non-metal total HAPs limits in Condition 4.1.4.b. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method 320 of Appendix A of 40 CFR Part 63, or ASTM D6348-12e1 provided that the test plan preparation and implementation provisions of Annexes A1 through A8 of ASTM D6348-12e1 are followed and the %R as determined in Annex A5 of ASTM D6348-12e1 is equal or greater than 70% and less than or equal to 130%. The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Results} = ((\text{Measured Concentration in Stack})/(\%R)) \times 100$$

Such tests shall be conducted with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output and 90% of the steam capacity of the HRSG or within 90% of recorded hourly steam output since initial startup. During the three test runs, the duct burner shall be firing during all periods of the testing at a rate that is represented of future operation of the duct burner.

Other HAPs to be measured as Total HAPs are:

Acetaldehyde	Ethylbenzene	n-Xylene
Acrolein	n-Hexane	p-Xylene
Benzene	Naphthalene	o-Xylene
Phenol	Propylene Oxide	
1,3-butadiene	Toluene	

This test shall consist of three (3) 120 minutes test runs. Records of the testing results; and process data, fuel/heat input, parameters used to determine the status of the SoLoNO_x™ mode of the combustion turbine record during the testing each event shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR13, R13-2334, 4.3.4.]

4.3.6. The permittee shall conduct subsequent testing for CO, formaldehyde, and total HAPs limits to demonstrate compliance of the limits in Condition 4.1.4.b. within 180 days when the average utilization of the duct burner is greater than 352,826 MMBtu per year on gross heat input basis over the previous 24 months from the most recent compliance demonstration Said subsequent test shall be conducted as outlined in Condition 4.3.5. of this permit.

As an alternative to conducting subsequent testing as required in the above paragraph, the permittee shall conduct tune-ups of the duct burner for TBD01 26 months from the initial compliance test as required in Condition 4.3.5 and once every 26 months thereafter. Such tune-ups shall be conducted in accordance with the manufacturer's instructions. If no manufacturer's instructions exist, the permittee shall develop a written tune-up procedure which shall include the following as a minimum:

- a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment.
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (permittee may delay the inspection until the next scheduled unit shutdown)
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, the optimization for NO_x emissions needs to consistent with the manufacturer's NO_x concentration setting point unless otherwise stated in this permit.

- e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. The permittee may need to measure the concentration of CO and O₂ upstream of the duct burner to optimize the emissions of CO from the actual duct burner

Records of these tune-ups shall include the following and maintained accordance with Condition 3.4.2.:

The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the duct burner. If concentrations of NO_x were taken during the tune-up of the unit, record of such measurements shall be included; and

A description of any corrective actions taken as a part of the tune-up.

Should the permittee elect to implement the tune-up work practice as an alternative to the subsequent testing, the permittee shall notify the Director in accordance with Condition 3.5.3, within 12 months following the initial compliance demonstration as required in Condition 4.3.5.

[45CSR13, R13-2334, 4.3.5.]

4.4. Recordkeeping Requirements

All Boilers except the Portable Boiler and Heaters

- 4.4.1. To determine compliance with the emission limits set forth set forth in Conditions 4.1.1., and 4.1.3., the permittee shall keep monthly records of the operating schedule, amount of fuel by type (e.g., refinery gas plus natural gas, natural gas) consumed within the boilers, individually. By no later than the 15th day of the following month, the permittee shall determine the monthly emissions and 12-month rolling total from each respective boiler. Mass NO_x emissions from each boiler shall be based on valid CEM data from the respective unit. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. *Compliance with the streamlined requirements will ensure compliance with CO-SIP-95-1 – Condition IV.3.A. To determine compliance with restrictions set forth in Section 4.1.6., the permittee shall document the frequency, length of time, amount of fuel oil consumed, and estimate of emissions during DOT maintenance and periods of natural gas curtailment in which fuel oil was combusted. To determine compliance with fuel oil sulfur content limits set forth in Section 4.1.6., the permittee shall keep records of the sulfur content of all fuel oil received for the purpose of combustion. Each batch of fuel oil shall have its sulfur content determined by test method ASTM D4294. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement E, Chapter 1.3 may be used to estimate emissions.*

[45CSR§8.3.3.; 45CSR13: R13-2334, 4.4.5, 4.4.4. CO-SIP-95-1 - Condition IV.3.A. (SIPed)]

All Boilers and Heaters Except H-201

- 4.4.2. To comply with the emission limits set forth set forth in Conditions 4.1.5., 4.1.6., 4.1.7., 4.1.8., 4.1.9, 4.1.10., 4.1.11., 4.1.12., 4.1.13., and 4.1.14., the permittee shall determine the monthly emissions and 12-month rolling total emissions from each respective heater by no later than the 15th day of the following month. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. *The operators of fuel burning units shall maintain a periodic exception report for each unit. Such reports shall include, but may not be*

~~limited to the date and time of start-ups and shutdowns. All such requirements, including notification by telephone, telefax, or other such method determined by the Director, shall be deemed to be satisfied when the reports are maintained on-site for a period of no less than five (5) years and shall be made available upon request to the Director or his/her duly authorized representative.~~

~~[45CSR§2-8.3.b.; 45CSR13: Permit R13-2334, 4.4.6, 4.4.5.]~~

- 4.4.3. The permittee shall maintain records of the operating schedule and the quantity of fuel consumed ~~by type consumed~~ in each ~~boiler and process heater monthly, at a minimum, fuel burning unit monthly, at a minimum,~~ but may record it more often at the discretion of the permittee.

~~[45CSR16; 40 CFR §60.48(g)(3); 45CSR§2-8.3.3.e.; 45CSR13: Permit R13-2334, 4.4.4, 4.4.6.]~~

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701

- 4.4.4. The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) subject to 45CSR§§10-3, 4 or 5 shall maintain on-site a record of all required monitoring data as established in a monitoring plan (see Appendix A) pursuant to 45CSR§10-8.2.3. e. Such records shall be made available to the Director or his duly authorized representative upon request. Such records shall be retained on-site for a minimum of five years.

~~[45CSR§10-8.3.1. a.; 45CSR13: Permit R13-2334, 4.4.7.]~~

- 4.4.5. ~~For Heaters H-201, H-500S, H-600S, and H-701, the permittee shall determine total daily sulfur dioxide emissions from each of these heaters attributable to each fuel fired during twenty-four (24) hours period that Sulfur dioxide emissions attributable to the combustion of refinery fuel gas shall be determined using continuous hydrogen sulfide monitoring data collected in accordance with Condition 4.2.7. in conjunction with daily determination of the RFG heating value and density and accurate daily measurements of the volume of RFG fired in each heater. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. The owner or operator of a fuel burning unit(s) or a combustion source(s) shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each unit in a manner specified 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§10-8.3.e.; 45CSR13: Permit R13-2334, 4.4.7, 8. CO-SIP-95-1 - Conditions V.4.A, and V.4.C. (SIPed)]~~

Boilers A and B, All Heaters (except H-101R, H-102R, H-500S, H-501R, H-441 and H-1101)

- 4.4.6. For any periods for which sulfur dioxide or oxides emissions data are not available ~~for demonstrating compliance with Condition 4.1.15., 4.1.16. and 4.1.5.b. of this permit,~~ the ~~permittee owner or operator of the affected facility~~ shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

~~[40 CFR §60.107(d); and 45CSR§16-4.1; 45CSR13: Permit R13-2334, 4.4.8, 14.]~~

- 4.4.7. The Company shall maintain records of the occurrence and duration of any start-up, shut-down or malfunction in the operation of sources subject to CO-SIP-95-1 ~~(Boilers A and B, All Heaters (except H-101R, H-102R, H-500S, H-501R, H-441 and H-1101))~~, any malfunction of air pollution control equipment or any periods during which a continuous monitoring system or device is inoperative.

~~[CO-SIP-95-1 - Condition VI.4. (SIPed)]~~

Boilers A and B

- 4.4.8. ~~The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring devices, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR60 recorded in a permanent form suitable for inspection. The file shall be retained in accordance with Condition 3.4.21. of this permit, except as follows: To determine compliance with the emission limits set forth for Boiler A and Boiler B set forth in Section 4.1.14, the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the two boilers, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4 may be used to estimate monthly emissions of all pollutants except SO₂. The SO₂ monthly emissions shall be estimated using a blended fuel emission factor of 0.00577 lb SO₂/MMBtu for 20% refinery gas and 80% natural gas. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with this limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.3.A. (SIPed) and 45CSR§10-3.1.e.~~
[45CSR13: Permit R13-2334, 4.4.9., 45CSR§30-5.1.c., CO-SIP-95-1—Condition IV.3.A. (SIPed) and and 45CSR§10-3.1.e.]

- a. ~~Where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard using a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under 1st paragraph of this condition, the permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.~~
- b. ~~Where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under 1st paragraph of this condition, the permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Director and/or Administrator.~~

[45CSR16; 40 CFR §§60.7(f), (f)(1), (f)(2); 45CSR13: Permit R13-2334, 4.4.9.]

Boiler C

- 4.4.9. ~~The following requirements shall be used in determining compliance with NSPS Subpart KKKK NO_x limits and identifying excess emissions from CEMs data. To determine compliance with the emission limits for Boiler C, set forth in Section 4.1.17, the permittee shall keep monthly records of the amount of natural gas consumed within Boiler C and the hours of operation. This information along with appropriate emission factors from EPA's Compilation of Air Pollutant Emission Factors AP-42 Fifth Edition, Volume I, Supplement D: Stationary Point and Area Sources (AP-42), Chapter 1.4. may be used to estimate monthly emissions of all pollutants except NO_x. The emission factor for NO_x shall be 0.050 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.~~
[45CSR13: Permit R13-2334, 4.4.10.]

- a. All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).
- b. 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 and lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR Part 60. For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂, a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.
- c. Correction of measured NO_x concentrations to 15 percent O₂ is not allowed for the NO_x NSPS Subpart KKKK limit listed in Condition 4.1.4.a.i.
- d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in Subpart D of 40 CFR Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c) and in Condition 4.5.1.
- e. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
- f. Calculate the hourly average NO_x emission rates, in units of the emission standards under 40 CFR §60.4320, using the following equation for units complying with the output-based standard:

1. For Simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \quad \text{(Equation 1 of 40 CFR 60, Subpart KKKK)}$$

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/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

2. For combined-cycle operation: For complying with the NO_x output-based standard, the permittee shall use Equation 1 of 40 CFR 60, Subpart KKKK, except that the gross energy output (P) is calculated as the sum of the total electrical and thermal 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:

$$P = (Pe)_t + (Pe)_c + P_s + P_o \quad \text{(Equation 2 of 40 CFR 60 Subpart KKKK)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)_c = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)_s = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_s = \frac{Q \cdot H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Equation 3 of 40 CFR 60 Subpart KKKK})$$

Where:

P_s = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10⁶ = conversion from Btu/h to MW.

P_o = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

g. “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. The permittee shall determine excess emissions for each 30-day rolling average NO_x emission rate is greater than the Subpart KKKK Standard in Condition 4.1.4.a.i. of this permit.

h. 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, diluent gas (CO₂ or O₂) 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.

i. A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

[45CSR16; 40 CFR §60.4350, §§60.4380(b)(1), (b)(2), (c)(2); 45CSR13: Permit R13-2334, 4.4.14.]

- 4.4.10. To demonstrate compliance with the annual emission limits set forth set forth in Conditions 4.1.4.b. and 4.1.4.f., the permittee shall determine the monthly emissions and 12-month rolling total emissions from Emission Point TDB01 by no later than the 15th day of the following month. For periods that CEMs data is not valid, the permittee shall use the best information available and operational status of the combustion turbine (e.g., SoLoNO_x non-SoLoNO_x mode, startup event, shutdown event) and duct burner to determine NO_x emissions for the period. For periods equal to and less than one operating hour of missing or invalid CEM data, the permittee is allowed to use the average of NO_x emissions of the hour before and hour after the missing hour if the operating status of the combustion turbine and duct burner was the same for all periods.

Said records, which should include calculations in determining NO_x for periods of the missing or invalid CEM data, shall be maintained in accordance with Condition 3.4.1. of this permit.

[45CSR13: Permit R13-2334, 4.4.15.]

(1) — Except as provided under 40 C.F.R. §§60.48c(g)(2) and (g)(3), the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) — As an alternative to meeting the requirements of 40 C.F.R. §60.48c(g)(1), the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO₂ 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.

(3) — As an alternative to meeting the requirements 40 C.F.R. §60.48c(g)(1), 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 this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO₂ 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.

~~[40 C.F.R. §60.48c(g) and 45CSR§16-4.1]~~

4.4.11. All records required under 40 C.F.R. 60 Subpart Dc shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

~~[40 C.F.R. §60.48c(i) and 45CSR§16-4.1]~~

Heaters H-101R, H-102R, H-201, H-441, H-501R, H-701, H-500S and H-600S

4.4.12. To demonstrate compliance with energy input limits set forth in Conditions 4.1.4.h. and 4.1.4.i., each month the permittee shall determine the hourly amount of energy input into the combustion turbine and duct burner on a daily average based for each operating day by no later than the 15th day of the following month. Said records shall be maintained in accordance with Condition 3.4.1. of this permit.
[45CSR13: Permit R13-2334, 4.4.16.]

~~To determine compliance with the emission limits set forth for H-101R, H-102R, and H-501R set forth in Section 4.1.18., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within both heaters for H-101R and H-102R, and individually for H-501R. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4, may be used to estimate monthly emissions of all pollutants except NO_x and SO₂. SO₂ emission factors shall be based on the 1995 SO₂-SIP and heating value (HHV) of 1019 Btu/scf, which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.4. (SIPed) and 45CSR§10-3.1.e.~~

~~[45CSR13: Permit R13-2334, 4.4.11. (H-101R, H-102R, H-501R), CO-SIP-95-1 — IV.4. (SIPed); 45CSR§10-3.1.e.]~~

- 4.4.13. ~~Each month the permittee shall identify all periods that the combustion turbine was not operating in the SoLoNO_x™ mode and reason for not operating the combustion turbine in the SoLoNO_x™ mode by no later than the 15th of the following month. The permittee shall maintain records either on-site or off-site and be accessible to the Director or his/her duly authorized representative within seven (7) calendar days of the request of records of the recorded parameters used to determine the status for the SoLoNO_x™ mode. Said records shall be maintained in accordance with Condition 3.4.2. of this permit except as stated in this condition.~~

~~[45CSR13: Permit R13-2334, 4.4.17.]~~

~~To determine compliance with the emission limits for H-441 set forth in Section 4.1.19., the permittee shall keep monthly records of the amount of natural gas consumed in the heater. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4 may be used to estimate monthly emissions.~~

~~[45CSR13: Permit R13-2334, 4.4.12. (H-441)]~~

- 4.4.14. ~~To determine compliance with the emission limits set forth for H-201, H-500 Series, H-600 Series, and H-701 in Sections 4.1.19. and 4.1.22., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the four heaters, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4. may be used to estimate monthly emissions of all pollutants except SO₂. SO₂ emission factors shall be based on the 1995 SIP and heating value (HHV), which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.5. and 7. (SIPed) and 45CSR§10-3.1.e.~~

~~[45CSR13: Permit R13-2334, 4.4.13. (H-201, H-500S, H-600S, H-701), CO-SIP-95-1 – IV.5. and 7. (SIPed); 45CSR§10-3.1.e.]~~

Heater H-901

- 4.4.15. ~~The permittee shall keep monthly records of the amount of refinery fuel gas consumed by H-901. To determine compliance with NO_x, SO₂, VOC, and CO emissions limits for H-901, emission factors from manufacturer's specifications along with fuel gas consumption may be used. To determine compliance with the PM emission limits, AP-42 emission factors Table 1.4. 2 (1998) along with fuel gas consumption data may be used. Said records shall be maintained on-site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.15.]~~

- 4.4.16. ~~The permittee shall maintain continuous record for the H₂S concentration in the refinery fuel gas consumed by H-901. Said records shall be maintained on-site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.16.]~~

Heater H-1101

- 4.4.17. ~~The permittee shall keep monthly records of the amount of natural gas consumed by H-1101. To determine compliance with the NO_x, SO₂, and CO emission limits for H-1101, the permittee may use manufacturer's specifications and natural gas consumption. To determine compliance with the VOC and PM emission limit,~~

~~natural gas consumption data and AP 42 Table 1.4-2 (1998) using an average gas high heating value (HHV) of 1020 BTU/scf may be used. Said records shall be maintained on-site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~
~~[45CSR13: Permit R13-2334, 4.4.17.]~~

Heaters H-101R, H-102R, H-500S, and H-501R

4.4.14. ~~4.4.18.~~ The permittee shall maintain records in accordance with 40 CFR §60.108a:

- a. Each permittee subject to the emissions limitations in 40 CFR §60.102a shall comply with the notification and recordkeeping requirements in 40 CFR §60.7 and other requirements as specified in 40 CFR §60.108a which shall include Condition 4.5.2. of this permit
- c. The permittee shall maintain the following records:
 6. Records of discharges greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device subject to Condition 4.1.15 of this permit. The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:
 - i. A description of the discharge.
 - ii. The date and time the discharge was first identified and the duration of the discharge.
 - iii. The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices.
 - v. For each discharge greater than 500 lb SO₂ in excess of the applicable short-term emissions limit in 40 CFR §60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H₂S in the fuel gas or the measured concentration of SO₂ in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices.
 - vii. For each discharge greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device, the cumulative quantity of H₂S and SO₂ released into the atmosphere. For fuel gas combustion devices, assume 99-percent conversion of H₂S to SO₂.
 - viii. The steps that the owner or operator took to limit the emissions during the discharge.
 - ix. The root cause analysis and corrective action analysis conducted as required in 40 CFR §60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under 40 CFR §60.103a(e).
 - x. For any corrective action analysis for which corrective actions are required in 40 CFR §60.103a(e), a description of the corrective action(s) completed within the first 45 days

following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

[Said records shall be maintained in accordance with Condition 3.4.2. of this permit.](#)
[45CSR16, 40 CFR §§60.108a(a) and (c) (6), 45CSR13: R13-2334, 4.4.~~10, 18, and 4.4.11-4.5.5.~~]

Portable Boiler

~~4.4.15.~~ ~~4.4.19.~~ In order to demonstrate compliance with the requirements of 4.1.~~23~~ ~~31~~ and 4.2.~~10~~ ~~15~~, the permittee shall record the number of hours of operation of the Portable Boiler on a monthly basis.
[45CSR13: R13-2334, 4.4.~~12, 19~~]

~~4.4.16.~~ ~~4.4.20.~~ In order to demonstrate compliance with the requirements of 4.1.~~24~~ ~~32~~, the permittee shall record all the dates on which the Portable Boiler is brought on site and removed from the site.
[45CSR13: R13-2334, 4.4.~~13, 20~~]

4.5. Reporting Requirements

All Boilers, Heaters H-101R, H-102R, H-441, H-501R, H-701, H-500S, H-600S, H-901, H-1101

4.5.1. The ~~permittee owner or operator of a fuel burning unit(s) subject to 45CSR2~~ shall report to the Director any malfunction of ~~Boilers A, B, C, and the duct burner when in operation for the combustion turbine 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 Director:
 1. The excess opacity period does not exceed thirty (30) minutes within any 24-hour period; and
 2. Excess opacity does not exceed 40%.
- b. The ~~permittee owner or operator~~ shall report to the Director any malfunction resulting in excess particulate matter or excess opacity, not meeting the criteria set forth in 45CSR§2-9.3.~~1 a~~, by telephone, ~~telefax~~, or e-mail by the end of the next business day after becoming aware of such condition. The ~~permittee owner or operator~~ shall file a certified written report concerning the malfunction with the Director within thirty (30) days ~~in accordance with Condition 3.5.3.~~ 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 program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.; 45CSR13: R13-2334, 4.5.1.]

Boilers A and B, Heaters H-101R, H-102R, H-501R, H-500S, H-600S, H-901

- 4.5.2. ~~For the boilers, process heaters, and duct burner subject to the H₂S standard in Conditions 4.1.15., 4.1.16., 4.1.15.; Boilers A and B to the NO_x standard in Condition 4.1.1.b.; and the Heater H-101R to the NO₂ standard in Condition 4.1.5.b., the permittee shall submit excess emissions and monitoring system performance report to the Director in accordance with Condition 3.5.3. for the six (6) month period of January 1 through June 30 and July 1 through December 31 by no later than 30th day following the end of each six (6) month period. The owner or operator shall submit a periodic exception report to the Director, in a manner specified by the Director. Such an exception report shall provide details of all excursions outside the range of measured emissions or monitored parameters established in an approved monitoring plan (see Appendix A) and shall include, but not be limited to, the time of the excursion, the magnitude of the excursion, the duration of the excursion, the cause of the excursion and the corrective action taken.~~

Commented [FT69]: Revised to 4.1.17.

Such reports shall contain the following information:

- a. The information and in the format listed in Appendix B of this permit for each pollutant monitored.
- b. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
- c. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
- d. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- e. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- f. For units subject to Condition 4.1.15 and excess emissions occurred as defined in Condition 4.2.6.e., the permittee shall provide the additional information.
 1. The date that the exceedance occurred.
 2. An explanation of the exceedance.
 3. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and
 4. A description of the action taken, if any.

5. The information described in 40 CFR §60.108a(c)(6) for all discharges listed in 40 CFR §60.108a(c)(6)
6. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.
- g. For units subject to Condition 4.1.16 and excess emissions occurred as defined in Condition 4.2.6.f., the permittee shall identify those excess emissions in the report.
- h. For units subject to Condition 4.1.17 and excess emissions occurred as defined in Condition 4.2.6.g., the permittee shall identify those periods, which includes the duration of the excess emission, the magnitude of the excess emission in the report, and actions taken to resolve and/or minimize the magnitude of the excess emissions.
- i. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
- j. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Director or Administrator.
- k. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.

[45CSR§10-8.3.2, ~~b.~~; 45CSR16; 40 CFR §§60.7(c) and (d), §60.107(f), §60.108a(d); 45CSR13: Permit R13-2334, 4.5.2.]

Boilers A and B, Heaters H-201, H-441, H-701, H-500S, H-600S

- 4.5.3. **For Boilers A and B, H-201, H-441, H-701, H-500S, H-600S:** The Company shall submit an excess emissions and monitoring systems performance report to the Director for all sources for which the Company is required to maintain and operate a continuous monitoring system or monitoring device for sulfur dioxide or hydrogen sulfide on a calendar monthly basis. All such reports shall be submitted by the 30th day following the end of each calendar month and shall contain the results of all determinations showing excess emissions regardless of whether the determinations are made by continuous monitoring data or by other methods established by CO-SIP-95-1. Written reports of excess emissions shall include the following information:
- a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, the date and time at which the excess emissions started and ended for each occurrence of excess emissions and the process operating time during the reporting period.

- b. Specific identification of each period of excess emissions that occurred during start-ups, shut-downs and malfunctions of the affected facility. Each malfunction report filed with the Director in accordance with Section 4.5.4. shall be referenced by report number with the date of occurrence and date of report submission noted.
- c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired or adjusted, such information shall be stated in the report.

If the total duration of excess emissions during the reporting period is less than one percent (1%) of the total operating time for the reporting period, and downtime for the continuous monitoring system for the reporting period is less than five percent (5%) of the total operating time for the reporting period, only the summary report form listed as Figure 1 in 40 CFR Part 60.7(d) shall be submitted, and the excess emission report described above need not be submitted unless requested by the Director. If the total duration of excess emissions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period, or the total continuous system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the summary report from and the excess emission report described above shall both be submitted to the Director.

[CO-SIP-95-1 - Condition VI.3. (SIPed)]

- 4.5.4. For Boilers A and B, H-201, H-441, H-701, H-500S, H-600S: The Company shall report to the Director, by telephone or telefax, any malfunction of such source or its air pollution control equipment which results in any excess sulfur dioxide emission rate or concentration within twenty-four (24) hours of becoming aware of such condition. The Company shall file a written report concerning the malfunction with the Director within ten (10) days, providing the following information:

- a. A detailed explanation of the factors involved or causes of the malfunction.
- b. The date and time of duration (with starting and ending times) of the period of excess emissions.
- c. An estimate of the mass of excess emissions discharged during the malfunction period.
- d. The maximum emission rate or concentration measured or otherwise determined during the malfunction in units of the applicable emissions standard.
- e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction.
- f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[CO-SIP-95-1 - Condition VI.7. (SIPed)]

Boiler-C

- ~~4.5.5. The permittee is responsible for submitting notification of the date of construction or reconstruction, anticipated startup, and actual startup and complying with 40 CFR §60.40c, 40 CFR §60.48c, and 40 CFR~~

~~§60.8. The permittee has complied with this requirement by submitting notification. Renotification will be required if modifications are made.~~

~~[40 CFR §60.48c and 45CSR§16 4.1.; 45CSR13: R13-2334, 4.5.3.]~~

~~4.5.5.~~ 4.5.6 The reporting period for the reports required under this subpart is each six-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.

~~[40 C.F.R. §60.48c(j) and 45CSR§16-4.1]~~

~~Heater H-901~~

~~4.5.7. For any periods for which sulfur dioxide or oxides emissions data are not available for H-901, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.~~

~~[40 CFR §60.107(d) and 45CSR§16 4.1; 45CSR13: Permit R13-2334, 4.5.4.]~~

~~Heaters H-101R, H-102R, H-500S, and H-501R~~

~~4.5.8. Each permittee subject to the emissions limitations in 40 CFR § 60.102a shall comply with the reporting requirements in 40 CFR § 60.7 and other requirements as specified in 40 CFR § 60.108a.~~

~~[45CSR16, 40 CFR §§ 60.108a (a), 45CSR13: R13-2334, 4.5.5.]~~

~~4.5.9. Each permittee subject to 40 CFR Part 60 Subpart Ja shall submit an excess emissions report for all periods of excess emissions according to the requirements of 40 CFR §60.7(c) except that the report shall contain the information specified in 40 CFR §60.108a(d)(1) through (7).~~

~~1. The date that the exceedance occurred;~~

~~2. An explanation of the exceedance;~~

~~3. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and~~

~~4. A description of the action taken, if any;~~

~~5. The information described in 40 CFR § 60.108a (c) (6) for all discharges listed in paragraph (c) (6).~~

~~6. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.~~

~~7. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.~~

~~[45CSR16, 40 CFR § 60.108a (d), 45CSR13, R13-2334, 4.5.5.]~~

4.5.6. The permittee shall prepare and submit an excess emission report on a semi-annual basis to the Director and Administrator for NO_x and SO₂ emissions from TBD01 as required by Subpart KKKK of 40 CFR 60. The initial compliance period is from initial startup up of combustion turbine (TDB01) to either December 31 or June 30 whichever date comes first. Subsequent reporting periods shall be every six months thereafter (e.g., January 1 to June 30, July 1 to December 31). Reports must be submitted no later than the 30th day following the end of the reporting period. Each report must contain the following information that occurred within the respective reporting period. Each report shall be submitted in accordance with Condition 3.5.3.

- a. Excess Emissions of sulfur dioxide emissions shall mean the total sulfur content of the fuel being combusted in the turbine exceeds the limit specified in 40 CFR §60.4330 (See Condition 4.1.4.a.ii. SO₂ limit for Subpart KKKK). An SO₂ excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. If electing to utilize the alternative monitor requirements for daily average H₂S concentration readings of the refinery fuel gas from the H₂S monitor as required in Condition 4.2.2.e., the daily average concentration (converted from H₂S into the form of the SO₂ emission standard stated in Condition 4.1.4.a.ii) shall be used to determine excess SO₂ emissions. An SO₂ excess emission occurs each unit operating hour included in any daily average concentration which exceeds the applicable limit and ending on the date and hour that a subsequent daily average demonstrates compliance with the SO₂ emission standard.
- b. Excess Emissions of NO_x means a specified averaging period (30-day rolling) over which the NO_x emissions are higher than the applicable emission limit in 40 CFR 60.4320 (See Condition 4.1.4.a.i. NO_x limit for Subpart KKKK).
- c. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you 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 start-up, shutdown, and malfunction.
- d. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each period of excess emissions. The process operating time during the reporting period.
- e. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted.
- f. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- g. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- h. The summary report form shall contain the information and be in the format shown in Appendix B of the permit unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

Commented [FT70]: Added as revised in R13-2334AK.

- i. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted, and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Administrator.
- j. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.

[45CSR16; 40 CFR §§60.7(c) and (d), §60.4375(a), §60.4380(b), §60.4385, §60.4395, 45CSR13: Permit R13-2334, 4.5.3.]

- 4.5.7. The permittee shall submit to the Director within 60 days of completion of CEMS performance evaluation for TDB01 two copies of the performance evaluation report to satisfy Part 60 notification requirements for certifying the CEMS.

[45CSR16; 40 CFR §§60.13(c) and (c)(2); 45CSR13: Permit R13-2334, 4.5.4.]

- 4.5.8. The permittee shall notify the Director within thirty (30) calendar days of switching to a different sampling schedule as allowed or required in Condition 4.2.1. of this permit. Such notification shall include the date of the actual switch and reason to include justification for switching the sampling schedule.

[45CSR13: Permit R13-2334, 4.5.5.]

- 4.5.9. The permittee shall submit a notification of the actual date of initial startup of TDB01 within 15 days after such date, to the Director and Administrator, in accordance with Condition 3.5.3. of this permit.

[45CSR16; 40 CFR §60.7(a)(3); 45CSR13: Permit R13-2334, 4.5.6.]

- 4.5.10. The permittee shall submit a notification acknowledging the provisions of Condition 4.1.3. (See 4.120. through 4.1.25. of this permit) of permit R13-2334 are no longer effective within 15 calendar days of the end date for Condition 4.1.25. of this permit (180 days after the actual initial startup date of TDB01) to the Director in accordance with Condition 3.5.3. of this permit.

[45CSR13: Permit R13-2334, 4.5.7.]

- 4.5.11. The permittee shall submit a notification for any exceedance of the annual emission limits in Condition 4.1.4. of this permit to the Director in accordance with Condition 3.5.3.

[45CSR13: Permit R13-2334, 4.5.8.]

4.6. Compliance Plan

- 4.6.1. None.

5.0 F1, T Load, OXIDIZER, MLD, MLDOX, and NH3OX Requirements

5.1. Limitations and Standards

5.1.1. The Main Flare [F1/00A-01], the Sour Gas Flare [F2/00A-03], the Truck Loading Thermal Oxidizer [OXIDIZER/00A-02], the Marine Loading Thermal Oxidizer [MLDOX/00A-04], and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX], are subject to the requirements of 45CSR6 including but 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 the use of the following formula:

$$\text{Emissions(lb/hr)} = F \times \text{Incinerator Capacity (tons/hr)}$$

where the factor, F, is as indicated in the table below:

Incinerator Capacity	F Factor
Less than 15,000 lbs/hr	5.43
15,000 lbs/hr or greater	2.72

Emission ID	Calculation	Limit (lbs/hr)
F1 [00A-01] and F2 [00A-03]	$2.72 \times 395,000 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	537.2
OXIDIZER [00A-02]	$5.43 \times 64.8 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	0.176
MLDOX [00A-04]	$5.43 \times 4600 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	12.5
NH3OX [00A-05]	$5.43 \times 416.08 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	1.13

- 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.
- c. Incinerators, including all associated equipment and grounds, shall be designed, operated and maintained so as to prevent the emission of objectionable odors.

[45CSR§§6-4.1., 4.3, 4.6.; 45CSR13: Permit R13-2334, 5.1.6.]

5.1.2. No person shall cause, suffer, allow, or permit the emission into open air from any source operation an in-stack sulfur dioxide concentration exceeding 2000 ppm by volume from existing source operations. Note: "In-stack" concentration as interpreted for a flare means the exhaust concentration after combustion.

[45CSR§10-4.1.; 45CSR13: Permit R13-2334 - 5.1.7.]

- 5.1.3. a. For the Main Flare F1, the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H₂S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. 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 limit.

[40 CFR §60.103a(h), 45CSR§16-4.1; 45CSR13: Permit R13-2334, 5.1.9., and CO-SIP-95-1 - Condition IV.9. (SIPed) (00A-01)]

- b. For the Sour Gas Flare [F2], the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf) determined hourly on a 3-hour

rolling average basis. 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 paragraph.
[40 CFR §60.104(a)(1), 45CSR§16-4.1; 45CSR13: Permit R13-2334, 5.1.10., and CO-SIP-95-1 - Condition IV.9. (SIPed) (00A-03)]

Compliance with these limits shall demonstrate compliance with the 50 gr/100dscf limit from CO-SIP-95-1, Condition IV.9.

- 5.1.4. During Truck Loading of gasoline, VOC emissions shall be controlled by the Loading Rack Thermal Oxidizer.
[45CSR13: Permit R13-2334, 5.1.3. (00A-02)]
- 5.1.5. Gas generated at the sour water stripper shall continue to be processed through the fuel gas treatment system and the Company shall exercise good operating and maintenance practices to maximize the utilization of the fuel gas treatment system to remove sulfur compounds from the sour gas stream and further provided, that in no event shall the emissions of sulfur dioxide from the sour gas flare exceed 18 lbs./hr.
[CO-SIP-95-1 - Condition IV.9. (SIPed)]
- 5.1.6. The permittee shall implement a program to investigate the cause of Acid Gas Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Acid Gas Flaring Incidents, and minimize Acid Gas Flaring Incidents. The permittee shall evaluate whether Acid Gas Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forth the Root Cause and all contributing causes of the Acid Gas Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Acid Gas Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.
- a. "Acid Gas Flaring Incident" means the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the AG Flaring Incident. "Acid Gas" means any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of amine solution.
- b. "Acid Gas Flaring" means the combustion of Acid Gas and/or Sour Water Stripper Gas in an Acid Gas Flaring Device. "Acid Gas Flaring Device" shall mean any device at EWVI that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The Acid Gas Flaring Device currently in service at EWVI is F2 [00A-03].
- c. "Sour Water Stripper Gas" shall mean the gas produced by the process of stripping refinery sour water.
- d. "Root Cause" means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.

- e. "Malfunction" means, as specified in 40 CFR Part §60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR13: Permit R13-2334, 5.1.16.]

- 5.1.7. In response to any Acid Gas or Hydrocarbon Flaring Incident from the Sour Gas Flare [F2], the permittee shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that Acid Gas or Hydrocarbon Flaring Incident.

[45CSR13: Permit R13-2334, 5.1.17.]

- 5.1.8. The permittee shall implement a program to investigate the cause of Hydrocarbon Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Hydrocarbon Flaring Incidents, and minimize Hydrocarbon Flaring Incidents. The permittee shall evaluate whether Hydrocarbon Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forth the Root Cause and all contributing causes of the Hydrocarbon Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Hydrocarbon Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.

- a. "Hydrocarbon Flaring Incident" means the continuous or intermittent Hydrocarbon Flaring, except for Acid Gas and/or Sour Water Stripper Gas, at a Hydrocarbon Flaring Device that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five-hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one Hydrocarbon Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the Hydrocarbon Flaring Incident.
- b. "Hydrocarbon Flaring" means the combustion of refinery-generated gases, except for Acid Gas and/or Sour Water Stripper Gas in a Hydrocarbon Flaring Device.
- c. "Hydrocarbon Flaring Device" means a flare device used to control (through combustion) any excess volume of a refinery generated gas other than Acid Gas and/or Sour Water Stripper Gas.
- d. "Root Cause" means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.
- e. "Malfunction" means, as specified in 40 CFR Part 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR13: Permit R13-2334, 5.1.18]

5.1.9. Emissions shall not exceed those listed below. Annual emission limits are based on a 12-month rolling basis.

Pollutant	Emission Point ID									
	F1 (pilot light)		F2 (pilot light)		TLOAD & OXIDIZER		MLD & MLDOX		NH3OX	
	TPM*	TPY	TPM*	TPY	TPM*	TPY	TPM*	TPY	TPM*	TPY
CO	0.007	0.074	0.013	0.129	0.21	2.12	0.27	2.67	0.80	7.96
NO _x	0.009	0.088	0.015	0.153	0.04	0.39	0.05	0.49	0.05	0.50
PM _{2.5}	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
PM ₁₀	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
PM	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
SO ₂					0.13	1.26	0.19	1.85	0.01	0.02
VOC	0.001	0.005	0.001	0.008	1.82	18.17	1.22	12.24	0.10	1.00
Total HAPs					0.32	3.22	0.13	1.3		
Benzene					0.03	0.32	0.01	0.08		

Pollutant	Emission Point ID			
	Railcar Unloading		Air Separator / Recovery Drum	
	TPM*	TPY	TPM*	TPY
VOC	1.46	17.55	0.36	4.35
Hexane	0.04	0.51	0.01	0.08
Benzene	0.04	0.49	0.01	0.08
Isooctane	0.01	0.04	0.01	0.01
Toluene	0.02	0.26	0.01	0.04
Ethylbenzene	0.01	0.04	0.01	0.01
Xylene	0.01	0.11	0.01	0.02
Total HAPs	0.12	1.45	0.02	0.23

*TPM = Tons per month

[45CSR13 - Permit R13-2334 - 5.1.1.]

5.1.10. The permittee shall not exceed the annual limits in the table below that correspond to the emission limits established in requirement 5.1.9. Annual quantities are based on a 12-month rolling basis.

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Marine Loading	Gasoline	62,031
	Light Crude Oil (including oil with a vapor pressure up to 11.0 psia)	306,600
	Diesel	37,065
	Kerosene	46,000
	Lube Oil/ Heavy Products	30,660
Truck Loading	Diesel	134,904
	Gasoline	134,904
	No. 6 Fuel Oil	13,650
	Kerosene	15,330
	Lube Oil/ Heavy Products	136,920

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Railcar Unloading	Waxy Crude	38,325
	Total Crude (Waxy & Penn)	76,650

[45CSR13 - Permit R13-2334 - 5.1.2.]

- 5.1.11. The Main Flare [F1] is an affected facility as that term is used in 40 CFR Part 60 and is subject to the requirements of 40 CFR Part 60, Subparts A and Ja . The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d) and with the applicable work practice standards of NSPS, Subpart Ja.

[45CSR16; 40 CFR §60.103a; 45CSR13: Permit R13-2334 - 5.1.13. and 5.1.15]

- 5.1.12. The Sour Gas Flare [F2] is an affected facility as that term is used in 40 CFR Part 60 and is subject to the requirements of 40 CFR Part 60, Subparts A and J. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d).

[45CSR13: Permit R13-2334, 5.1.14.]

- 5.1.13. Marine Loading.

- a. During marine loading of gasoline and light crude oil, VOC emissions shall be controlled by the Marine Barge Loading Thermal Oxidizer [MLDOX/ 00A-04]. MLDOX shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 98% for VOCs.

- b. All vessels loaded from the Marine Loading Dock (MLD) shall be submerged filled.

[45CSR13: Permit R13-2334, 5.1.4.]

- 5.1.14. Emissions from the Ammonia Destruction Unit (ADU) shall be routed to the ADU Thermal Oxidizer [NH3OX/00A-05] at all times that the ADU is in operation. The thermal oxidizer [NH3OX] shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 99.9% for VOCs.

[45CSR13: Permit R13-2334, 5.1.5.]

- 5.1.15. No refined products (e.g. gasoline, naphtha, ethanol, diesel) shall be received via rail.

[45CSR13: Permit R13-2334, 5.1.8.]

- 5.1.16. Existing sources with emissions less than 10 and 25 tons must meet the submerged fill standards of 46 CFR 153.282.

- a. The discharge point of a cargo tank filling line must be no higher above the bottom of the cargo tank or sump than 10 cm (approx. 4 in.) or the radius of the filling line, whichever is greater.

[46 C.F.R. §153.282]

[40 C.F.R. §63.560(a)(4); 45CSR34] (MLD and MLDOX)

- 5.1.17. Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.

[40 C.F.R. §60.502(a); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.18. The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in 40 C.F.R. §60.502(c).

[40 C.F.R. §60.502(b); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.19. Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:

- a. The owner or operator shall obtain the vapor tightness documentation described in 40 C.F.R. §60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.
- b. The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.
- c.
 - i. The owner or operator shall cross-check each tank identification number obtained in 40 C.F.R. §60.502(e)(2) with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded, unless either of the following conditions is maintained:
 - A. If less than an average of one gasoline tank truck per month over the last 26 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed each quarter; or
 - B. If less than an average of one gasoline tank truck per month over the last 52 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed semiannually.
 - ii. If either the quarterly or semiannual cross-check provided in 40 C.F.R. §§60.502(e)(3)(i)(A) through (B) reveals that these conditions were not maintained, the source must return to biweekly monitoring until such time as these conditions are again met.
- d. The terminal owner or operator shall notify the owner or operator of each non-vapor-tight gasoline tank truck loaded at the affected facility within 1 week of the documentation cross-check in 40 C.F.R. §60.502(e)(3).
- e. The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.
- f. Alternate procedures to those described in 40 C.F.R. §60.502(e)(1) through (5) for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.

[40 C.F.R. §60.502(e); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.20. The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

[40 C.F.R. §60.502(f); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.21. The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

[40 C.F.R. §60.502(g); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.22. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in §60.503(d).

[40 C.F.R. §60.502(h); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.23. Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

[40 C.F.R. §60.502(j); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.24. Each owner or operator of an affected source under this subpart must comply with the requirements of 40 C.F.R. §§63.11085(a) and (b).

(a) You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. 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.

(b) You must keep applicable records and submit reports as specified in 40 C.F.R. §63.11094(g) and 40 C.F.R. §63.11095(d).

[40 C.F.R. §63.11085; 45CSR34] (T Load) (During gasoline loading only)

- 5.1.25. The permittee must meet each emission limit and management practice in Table 2 to 40 C.F.R. 63 Subpart BBBBBB that applies to you.

If you own or operate ...	Then you must ...
1. A bulk gasoline terminal loading rack(s) with a gasoline throughput (total of all racks) of 250,000 gallons per day, or greater. Gallons per day is calculated by summing the current day's throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365	(a) Equip your loading rack(s) with a vapor collection system designed to collect the TOC vapors displaced from cargo tanks during product loading; and
	(b) Reduce emissions of TOC to less than or equal to 80 mg/l of gasoline loaded into gasoline cargo tanks at the loading rack; and
	(c) Design and operate the vapor collection system to prevent any TOC vapors collected at one loading rack or lane from passing through another loading rack or lane to the atmosphere; and
	(d) Limit the loading of gasoline into gasoline cargo tanks that are vapor tight using the procedures specified in §60.502(e) through (j) of this chapter. For the purposes of this section, the term "tank truck" as used in

	§60.502(e) through (j) of this chapter means “cargo tank” as defined in §63.11100.

[40 C.F.R. §63.11088(a); Table 2 to 40 C.F.R 63 Subpart BBBB, 45CSR34] (T Load) (During gasoline loading only)

5.1.26. Requirements for equipment leak inspections at a bulk gasoline terminal, bulk plant, pipeline breakout station, or pipeline pumping station.

- (a) Each owner or operator of a bulk gasoline terminal, bulk plant, pipeline breakout station, or pipeline pumping station subject to the provisions of this subpart shall perform a monthly leak inspection of all equipment in gasoline service, as defined in 40 C.F.R. §63.11100. For this inspection, detection methods incorporating sight, sound, and smell are acceptable.
- (b) A log book shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log book shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.
- (c) Each detection of a liquid or vapor leak shall be recorded in the log book. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in 40 C.F.R. §63.11089(d) of this section.
- (d) Delay of repair of leaking equipment will be allowed if the repair is not feasible within 15 days. The owner or operator shall provide in the semiannual report specified in 40 C.F.R. §63.11095(b), the reason(s) why the repair was not feasible and the date each repair was completed.
- (e) You must comply with the requirements of this subpart by the applicable dates specified in 40 C.F.R. §63.11083.
- (f) You must submit the applicable notifications as required under 40 C.F.R. §63.11093.
- (g) You must keep records and submit reports as specified in 40 C.F.R. §§63.11094 and 63.11095.

[40 C.F.R. §63.11089; 45CSR34] (T Load) (During gasoline loading only)

5.2. Monitoring Requirements

5.2.1. The permittee shall monitor the PM emissions by conducting visible emissions checks in accordance with Section 4.2.1. of this permit.

[45CSR13 - R13-2334 - 5.2.1.]

5.2.2. To determine compliance with the emission rate limits set forth in Section 5.1.9., the permittee shall monitor hours of operation for pilot and non-pilot conditions of the Main Flare [F1] and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX]. Compliance with yearly limits shall be based on a 12-month rolling basis.

[45CSR13 - Permit R13-2334 - 5.2.2.]

5.2.3. To determine compliance with the annual emission rate limits set forth in Section 5.1.9. for the OXIDIZER and MLDOX, the permittee may estimate emissions using the monthly loading records, along with the

appropriate emission factors for loading losses from AP-42, Chapter 5.2 (7/08). Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13 - Permit R13-2334 - 5.2.3.]

- 5.2.4. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.13 for MLDOX, OXIDIZER, and NH3OX.

[45CSR16, 40 CFR §60.13, 45CSR13: R13-2334, 5.2.4]

- 5.2.5. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.107a for F1:

The owner or operator of a flare that is subject to the H₂S concentration requirement in Section 5.1.3.a. shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

- i. The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H₂S.
- ii. The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.
- iii. The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H₂S monitor.
- iv. Flares 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 fuel gas combustion devices or flares.
- v. The owner or operator of a flare subject to 40 CFR 60.103(c) through (e) may use the instrument required in 40 CFR §60.107a(e)(1) to demonstrate compliance with the H₂S concentration requirement in 40 CFR §60.103a(h) if the owner or operator complies with the requirements of 40 CFR §§60.107a(e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in 40 CFR §60.107a(e)(1) is used to demonstrate compliance with the H₂S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in 40 CFR §60.103a(h).
- vi. The owner or operator of modified flare that meets all three criteria in paragraphs A. through C. below shall comply with the requirements of Section 5.2.5.i. through v. no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to 40 CFR §60.13(i) until the flare is in compliance with requirements of Section 5.2.5.i. through v.
 - A. The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under §60.100a.
 - B. The owner or operator had an approved alternative monitoring plan or plans pursuant to §60.13(i) for all fuel gases combusted in the flare.

- C. The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

[45CSR16, 40 CFR §60.107a(a)(2), 45CSR13: Permit R13-2334, 5.2.5.]

- 5.2.6. In order to determine compliance with the railcar unloading throughput of condition 5.1.10, the permittee shall monitor and record the amount and type of crude oil unloaded from railcars on a monthly basis.

[45CSR13: Permit R13-2334, 5.2.6.]

- 5.2.7. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) while gasoline vapors are displaced to the vapor processor systems, as specified in 40 C.F.R. §63.11092(b)(1) through (5). For each facility conducting a performance test under paragraph 40 C.F.R. §63.11092(a)(1), and for each facility utilizing the provisions of 40 C.F.R. §63.11092(a)(2) or (a)(3), the CMS must be installed by January 10, 2011.

- (5) If you have chosen to comply with the performance testing alternatives provided under 40 C.F.R. §63.11092(a)(2) or (a)(3), the monitored operating parameter value may be determined according to the provisions in paragraph 40 C.F.R. §63.11092(b)(5)(i) or (b)(5)(ii).

- (i) Monitor an operating parameter that has been approved by the Administrator and is specified in your facility's current enforceable operating permit. At the time that the Administrator requires a new performance test, you must determine the monitored operating parameter value according to the requirements specified in 40 C.F.R. §63.11092(b).
- (ii) Determine an operating parameter value based on engineering assessment and the manufacturer's recommendation and submit the information specified in paragraph 40 C.F.R. §63.11092(b)(4) for approval by the Administrator. At the time that the Administrator requires a new performance test, you must determine the monitored operating parameter value according to the requirements specified in 40 C.F.R. §63.11092(b) of this section.

Note: In accordance with 40 CFR §63.11092(a)(2) and §63.11092(b)(5)(i), the OXIDIZER is equipped with a monitoring system to measure and record the temperature during gasoline truck loading events. The OXIDIZER temperature must achieve 1,000 °F during each loading event.

[40 C.F.R. §63.11092(b)(5);45CSR34] (T Load and OXIDIZER)

- 5.2.8. Each owner or operator of a bulk gasoline terminal subject to the provisions of 40 C.F.R. 63 Subpart BBBBBB shall comply with the requirements in 40 C.F.R. §63.11092(d)(1) through (4).

- (1) Operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the operating parameter value for the parameters described in 40 C.F.R. §63.11092(b)(1).
- (2) In cases where an alternative parameter pursuant to 40 C.F.R. §63.11092(b)(1)(iv) or 40 C.F.R. §63.11092 (b)(5)(i) is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value.

- (3) Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as appropriate, shall constitute a violation of the emission standard in 40 C.F.R. §63.11088(a), except as specified in 40 C.F.R. §63.11092(d)(4).
- (4) For the monitoring and inspection, as required under 40 C.F.R. §§63.11092(b)(1)(i)(B)(2) and (b)(1)(iii)(B)(2), malfunctions that are discovered shall not constitute a violation of the emission standard in 40 C.F.R. §63.11088(a) if corrective actions as described in the monitoring and inspection plan are followed. The owner or operator must:
 - (i) Initiate corrective action to determine the cause of the problem within 1 hour;
 - (ii) Initiate corrective action to fix the problem within 24 hours;
 - (iii) Complete all corrective actions needed to fix the problem as soon as practicable consistent with good air pollution control practices for minimizing emissions;
 - (iv) Minimize periods of start-up, shutdown, or malfunction; and
 - (v) Take any necessary corrective actions to restore normal operation and prevent the recurrence of the cause of the problem.

[40 C.F.R. §63.11092(d);45CSR34] (T Load and OXIDIZER)

- 5.2.9. When loading barges with gasoline or crude, the MLDOX shall be operated above the minimum temperature established during the performance test demonstrating the device achieves a minimum control efficiency of 98% for VOCs. For naphtha loading, the minimum operating temperature is 899 °F. For light crude loading, the minimum operating temperature is 1346 °F. The MLDOX shall be equipped with two (2) thermocouples with the second thermocouple serving as backup. The thermocouples shall have an accuracy/precision of at least $\pm 0.75\%$. The MLDOX temperature shall be continuously monitored and recorded using an electronic monitoring system. Continuous means at least one data point is recorded in each quadrant of the hour with a 1-hour block averaging period. MLDOX startup/shutdown periods are excluded from averaging. An excursion shall be defined as a temperature below the minimum operating temperature. Excursions trigger a system inspection and corrective action.

Monitoring equipment shall be installed and verified according to the manufacturer's specifications.

[45CSR§30-5.1.c; 40 C.F.R. 64.6(c)] (MLDOX)

- 5.2.10. When the Ammonia Destruction Unit (ADU) is in operation, the NH3OX shall be operated above the minimum temperature established during the performance test demonstrating the device achieves a minimum control efficiency of 99.9% for VOCs. The minimum operating temperature is 1630 °F. The NH3OX shall be equipped with two (2) thermocouples with the second thermocouple serving as backup. The thermocouples shall have an accuracy/precision of at least $\pm 0.75\%$. The NH3OX temperature shall be continuously monitored and recorded using an electronic monitoring system. Continuous means at least one data point is recorded in each quadrant of the hour with a 3-hour block averaging period. ADU/NH3DOX startup/shutdown periods are excluded from averaging. An excursion shall be defined as a temperature below the minimum operating temperature. Excursions trigger a system inspection and corrective action.

Monitoring equipment shall be installed and verified according to the manufacturer's specifications.

[45CSR§30-5.1.c; 40 C.F.R. 64.6(c)] (NH3OX)

- 5.2.11. **Commencement of operation.** The owner or operator shall conduct the monitoring required under this part upon issuance of a part 70 or 71 permit that includes such monitoring, or by such later date specified in the permit pursuant to §64.6(d).
[45CSR§30-5.1.c; 40 C.F.R. §64.7(a)] (MLDOX and NH3OX)
- 5.2.12. **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 C.F.R. §64.7(b)] (MLDOX and NH3OX)
- 5.2.13. **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 this part, 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 C.F.R. §64.7(c)] (MLDOX and NH3OX)
- 5.2.14. **Response to excursions or exceedances.**
- 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.
 - 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 C.F.R. §64.7(d)] (MLDOX and NH3OX)
- 5.2.15. **Documentation of need for improved monitoring.** After approval of monitoring under this part, 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 C.F.R. §64.7(e)] (MLDOX and NH3OX)

5.2.16. **Quality improvement plan (QIP) requirements.**

- a. Based on the results of a determination made under §64.7(d)(2), the Administrator or the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with §64.6(c)(3), the part 70 or 71 permit may specify an appropriate threshold, such as an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, for requiring the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.
- b. Elements of a QIP:
 1. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.
 2. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:
 - i. Improved preventive maintenance practices.
 - ii. Process operation changes.
 - iii. Appropriate improvements to control methods.
 - iv. Other steps appropriate to correct control performance.
 - v. More frequent or improved monitoring (only in conjunction with one or more steps under paragraphs (b)(2)(i) through (iv) of this section).
- c. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.
- d. Following implementation of a QIP, upon any subsequent determination pursuant to §64.7(d)(2) the Administrator or the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:
 1. Failed to address the cause of the control device performance problems; or
 2. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.
- e. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

[45CSR§30-5.1.c; 40 C.F.R. §64.8] (MLDOX and NH3OX)

5.3. Testing Requirements

- 5.3.1. The hydrogen sulfide concentrations of the sour gas stream used to determine daily compliance with Section 5.1.3. shall be determined on days when the fuel gas treatment system is not operating by running 2-hour samples of the hydrogen sulfide content of the water entering and exiting the sour water stripper unit. At least three (3) 2-hour samples shall be taken during each 24-hour period at approximately 8-hour intervals.

[CO-SIP-95-1 - Condition V.9. (SIPed)]

- 5.3.2. The permittee shall conduct an initial performance test of MLDOX to demonstrate compliance with the control efficiency provided in the Emissions Unit Table (minimum of 98%), Section 1.1, and shall establish operating parameters in accordance with the most recent performance test.

[45CSR13: Permit R13-2334, 5.3.1. (00A-04)]

- 5.3.3. The permittee shall meet all applicable performance tests requirements of 40 CFR §60.8 for MLDOX, OXIDIZER, and NH3OX.

[45CSR16, 40 CFR §60.8, 45CSR13: R13-2334, 5.3.2]

- 5.3.4. The permittee shall calculate an annual estimate of HAP emissions from gasoline and light crude oil from marine tank vessel loading operations. Emission estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source.

The recordkeeping requirements of 40 CFR §63.567(j)(4) and the emission estimation requirements of 40 CFR §63.565(l) apply to existing sources with emissions less than 10 and 25 tons.

[45CSR34, 40 CFR §§63.560(a)(3) and 63.565(l), 45CSR13: R13-2334, 5.3.4]

- 5.3.5. Immediately before the performance test required to determine compliance with 40 C.F.R. §60.502 (b), (c), and (h), the owner or operator shall use Method 21 to monitor for leakage of vapor all potential sources in the terminal's vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 10,000 ppm (as methane) or greater before conducting the performance test.

[40 C.F.R. §60.503(b); 45CSR16] (T Load)

- 5.3.6. The owner or operator shall determine compliance with the standards in §60.502 (b) and (c) as follows:

1. The performance test shall be 6 hours long during which at least 300,000 liters of gasoline is loaded. If this is not possible, the test may be continued the same day until 300,000 liters of gasoline is loaded or the test may be resumed the next day with another complete 6-hour period. In the latter case, the 300,000-liter criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.
2. If the vapor processing system is intermittent in operation, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.
3. The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K \sum_{i=1}^n (V_{est} C_{ei}) / L 10^6$$

where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{est} = volume of air-vapor mixture exhausted at each interval “i”, scm.

C_{ei} = concentration of total organic compounds at each interval “i”, ppm.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

i = emission testing interval of 5 minutes.

K = density of calibration gas, 1.83×10^6 for propane and 2.41×10^6 for butane, mg/scm.

4. The performance test shall be conducted in intervals of 5 minutes. For each interval “i”, readings from each measurement shall be recorded, and the volume exhausted (V_{est}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.
5. The following methods shall be used to determine the volume (V_{est}) air-vapor mixture exhausted at each interval:
 - i. Method 2B shall be used for combustion vapor processing systems.
 - ii. Method 2A shall be used for all other vapor processing systems.
6. Method 25A or 25B shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. The calibration gas shall be either propane or butane. The owner or operator may exclude the methane and ethane content in the exhaust vent by any method (e.g., Method 18) approved by the Administrator.
7. To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

[40 C.F.R. §60.503(c); 45CSR16] (T Load)

5.3.7. The owner or operator shall determine compliance with the standard in §60.502(h) as follows:

1. A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ± 2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.

2. During the performance test, the pressure shall be recorded every 5 minutes while a gasoline truck is being loaded; the highest instantaneous pressure that occurs during each loading shall also be recorded. Every loading position must be tested at least once during the performance test.

[40 C.F.R. §60.503(d); 45CSR16] (T Load)

- 5.3.8. The MLDOX and NH3OX thermocouples shall be inspected no less than once per year to verify accuracy according to the manufacturer's recommendations.
[45CSR§30-5.1.c; 40 C.F.R. §64.6(c)] (MLDOX and NH3OX)

5.4. Recordkeeping Requirements

- 5.4.1. To determine compliance with the loading emission limits set forth in Section 5.1.9., the permittee shall keep a monthly record of the volume and type of each product/product type loaded at each truck loading station and marine barge loading station and whether or not the VOC emissions were controlled using the control devices [OXIDIZER or MLDOX]. AP-42 emission factors for flares and transportation and marketing of petroleum liquids (Chapter 5.2, 1/95) or test data may be used to estimate emissions.
[45CSR13: Permit R13-2334, 5.4.1.]

- 5.4.2. To determine compliance with the annual benzene emission limit set forth in Section 5.1.9., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of benzene present in petroleum liquids processed and transported at the facility. The following equation shall be to determine monthly and yearly emissions.

Benzene Emissions (tpm or tpy) = (Total VOCs (tpm or tpy)) x (Actual Benzene Vapor Weight %)

Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.
[45CSR13: Permit R13-2334, 5.4.2.]

- 5.4.3. To demonstrate compliance with the operational limit for the main/sour gas flare [F1] established in section 5.1.10., the permittee shall maintain records of the hours that non-pilot emissions were sent to the flare. The annual limit shall be recorded on a 12-month rolling total basis.

[45CSR13: Permit R13-2334, 5.4.3.]

- 5.4.4. The permittee shall meet all applicable notification and record keeping requirements of 40 CFR §60.7 for OXIDIZER, MLDOX, and NH3OX.

[45CSR16, 40 CFR §60.7, 45CSR13: Permit R13-2334, 5.4.4.]

- 5.4.5. The permittee shall retain records of the emissions estimates determined in 40 CFR §63.565(l) and requirement 5.3.4. of this permit and their actual throughputs by commodity for gasoline and light crude oil, for 5 years.

[45CSR34, 40 CFR §§63.560(a)(3) and 63.567(j)(4), 45CSR13: Permit R13-2334, 5.4.6.]

- 5.4.6. The tank truck vapor tightness documentation required under §60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.

[40 C.F.R. §60.505(a); 45CSR16] (T Load)

5.4.7. The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:

1. Test title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.
2. Tank owner and address.
3. Tank identification number.
4. Testing location.
5. Date of test.
6. Tester name and signature.
7. Witnessing inspector, if any: Name, signature, and affiliation.
8. Test results: Actual pressure change in 5 minutes, mm of water (average for 2 runs).

[40 C.F.R. §60.505(b); 45CSR16] (T Load)

5.4.8. A record of each monthly leak inspection required under §60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:

1. Date of inspection.
2. Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).
3. Leak determination method.
4. Corrective action (date each leak repaired; reasons for any repair interval in excess of 15 days).
5. Inspector name and signature.

[40 C.F.R. §60.505(c); 45CSR16] (T Load)

5.4.9. The terminal owner or operator shall keep documentation of all notifications required under §60.502(e)(4) on file at the terminal for at least 2 years.

[40 C.F.R. §60.505(d); 45CSR16] (T Load)

5.4.10. As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 40 C.F.R. §§60.505(a), (c), and (d) of this section, an owner or operator may comply with the requirements in either 40 C.F.R. §§60.505(e)(1) or (2).

1. An electronic copy of each record is instantly available at the terminal.
 - i. The copy of each record in 40 C.F.R. §§60.505(e)(1) is an exact duplicate image of the original paper record with certifying signatures.

- ii. The permitting authority is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R.§§60.505(e)(1).
- 2. For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.
 - i. The copy of each record in 40 C.F.R.§§60.505(e)(2) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The permitting authority is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R.§§60.505(e)(2).

[40 C.F.R. §60.505(e); 45CSR16] (T Load)

- 5.4.11. The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.

[40 C.F.R. §60.505(f); 45CSR16] (T Load)

- 5.4.12. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as specified in paragraphs (b)(1) through (3) of 40 C.F.R. §63.11094.
- 1. Annual certification testing performed under §63.11092(f)(1) and periodic railcar bubble leak testing performed under §63.11092(f)(2).
 - 2. The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:
 - i. Name of test: Annual Certification Test—Method 27 or Periodic Railcar Bubble Leak Test Procedure.
 - ii. Cargo tank owner's name and address.
 - iii. Cargo tank identification number.
 - iv. Test location and date.
 - v. Tester name and signature.
 - vi. Witnessing inspector, if any: Name, signature, and affiliation.
 - vii. Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.
 - viii. Test results: Test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

3. If you are complying with the alternative requirements in §63.11088(b), you must keep records documenting that you have verified the vapor tightness testing according to the requirements of the Administrator.

[40 C.F.R. §63.11094(b);45CSR34] (T Load)

- 5.4.13. As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 40 C.F.R. §63.11094(b), an owner or operator may comply with the requirements in either 40 C.F.R. §63.11094(c)(1) or (c)(2).
 1. An electronic copy of each record is instantly available at the terminal.
 - i. The copy of each record in 40 C.F.R. §63.11094(c)(1) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The Administrator is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R. §63.11094(c)(1).
 2. For facilities that use a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by the Administrator's delegated representatives during the course of a site visit, or within a mutually agreeable time frame
 - i. The copy of each record in 40 C.F.R. §63.11094(c)(2) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The Administrator is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R. §63.11094(c)(2).

[40 C.F.R. §63.11094(c);45CSR34] (T Load)

- 5.4.14. Each owner or operator subject to the equipment leak provisions of §63.11089 shall prepare and maintain a record describing the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under §63.11089, the record shall contain a full description of the program.

[40 C.F.R. §63.11094(d);45CSR34] (T Load)

- 5.4.15. Each owner or operator of an affected source subject to equipment leak inspections under §63.11089 shall record in the log book for each leak that is detected the information specified in 40 C.F.R. §§63.11094(e)(1) through (7).
 1. The equipment type and identification number.
 2. The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, or smell).
 3. The date the leak was detected and the date of each attempt to repair the leak.
 4. Repair methods applied in each attempt to repair the leak.

5. “Repair delayed” and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak.
6. The expected date of successful repair of the leak if the leak is not repaired within 15 days.
7. The date of successful repair of the leak.

[40 C.F.R. §63.11094(e);45CSR34] (T Load)

- 5.4.16. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:
1. Keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.11092(b) or §63.11092(e). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.
 2. Record and report simultaneously with the Notification of Compliance Status required under §63.11093(b):
 - i. All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under §63.11092(b) or §63.11092(e); and
 - ii. The following information when using a flare under provisions of §63.11(b) to comply with §63.11087(a):
 - A. Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and
 - B. All visible emissions (VE) readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under §63.11092(e)(3).
 3. Keep an up-to-date, readily accessible copy of the monitoring and inspection plan required under §63.11092(b)(1)(i)(B)(2) or §63.11092(b)(1)(iii)(B)(2).
 4. Keep an up-to-date, readily accessible record of all system malfunctions, as specified in §63.11092(b)(1)(i)(B)(2)(v) or §63.11092(b)(1)(iii)(B)(2)(v).
 5. If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in §63.11092(b), the owner or operator shall submit a description of planned reporting and recordkeeping procedures.

[40 C.F.R. §63.11094(f);45CSR34] (T Load)

- 5.4.17. Each owner or operator of an affected source under this subpart shall keep records as specified in 40 C.F.R. §63.11094(g)(1) and (2).

1. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
2. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.11085(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 C.F.R. §63.11094(g);45CSR34] (T Load)

5.4.18. General recordkeeping requirements.

1. The owner or operator shall comply with the recordkeeping requirements specified in §70.6(a)(3)(ii) of this chapter. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
2. 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 C.F.R. §64.9(b)] (MLDOX and NH3OX)

- 5.4.19. The temperature data for MLDOX and NH3OX shall be recorded and maintained in an electronic database and records shall be maintained for at least 5 years.

[45CSR§30-5.1.c; 40 C.F.R. §64.9(b)] (MLDOX and NH3OX)

5.5. Reporting Requirements

- 5.5.1. For the Main Flare [F1], the permittee shall comply with the reporting requirements of 40 CFR Part 60, Subpart Ja.
[45CSR16, 40 CFR§60.108a, 45CSR13: Permit R13-2334, 5.5.1.]
- 5.5.2. For the Sour Gas Flare [F2], the permittee shall comply with the reporting requirements of 40 CFR 60, Subpart J.
[45CSR16, 40 CFR §60.107(f), 45CSR13: Permit R13-2334, 5.5.2.]
- 5.5.3. The permittee shall meet all applicable reporting requirements of 40 CFR §60.19 for OXIDIZER, MLDOX, and NH3OX.
[45CSR16, 40 CFR §60.19, 45CSR13 - Permit R13-2334 - 5.5.3.]
- 5.5.4. Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:
 1. For loading racks, each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility.

2. For equipment leak inspections, the number of equipment leaks not repaired within 15 days after detection.

[40 C.F.R. §§63.11095(a)(2) and (3);45CSR34] (T Load)

- 5.5.5. Each owner or operator of an affected source subject to the control requirements of this subpart shall submit an excess emissions report to the Administrator at the time the semiannual compliance report is submitted. Excess emissions events under this subpart, and the information to be included in the excess emissions report, are specified in 40 C.F.R. §§63.11095(b)(1) through (5).
 1. Each instance of a non-vapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.
 2. Each reloading of a non-vapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.11094(b).
 3. Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.11092(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.
 4. Each instance in which malfunctions discovered during the monitoring and inspections required under §63.11092(b)(1)(i)(B)(2) and (b)(1)(iii)(B)(2) were not resolved according to the necessary corrective actions described in the monitoring and inspection plan. The report shall include a description of the malfunction and the timing of the steps taken to correct the malfunction.
 5. For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:
 - i. The date on which the leak was detected;
 - ii. The date of each attempt to repair the leak;
 - iii. The reasons for the delay of repair; and
 - iv. The date of successful repair.

[40 C.F.R. §63.11095(b); 45CSR34] (T Load)

- 5.5.6. Each owner or operator of a bulk gasoline plant or a pipeline pumping station shall submit a semiannual excess emissions report, including the information specified in 40 C.F.R. §63.11095(a)(3) and (b)(5), only for a 6-month period during which an excess emission event has occurred. If no excess emission events have occurred during the previous 6-month period, no report is required.

[40 C.F.R. §63.11095(c); 45CSR34] (T Load)

- 5.5.7. Each owner or operator of an affected source under this subpart shall submit a semiannual report including the number, duration, and a brief description of each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected

source to minimize emissions in accordance with §63.11085(a), including actions taken to correct a malfunction. The report may be submitted as a part of the semiannual compliance report, if one is required. Owners or operators of affected bulk plants and pipeline pumping stations are not required to submit reports for periods during which no malfunctions occurred.

[40 C.F.R. §63.11095(d); 45CSR34] (T Load)

5.5.8. General reporting requirements.

1. On and after the date specified in §64.7(a) by which the owner or operator must use monitoring that meets the requirements of this part, the owner or operator shall submit monitoring reports to the permitting authority in accordance with §70.6(a)(3)(iii) of this chapter.
2. A report for monitoring under this part shall include, at a minimum, the information required under §70.6(a)(3)(iii) of this chapter and the following information, as applicable:
 - i. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
 - ii. 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
 - iii. A description of the actions taken to implement a QIP during the reporting period as specified in §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 C.F.R. §64.9(a)] (MLDOX and NH3OX)

5.6. Compliance Plan

- 5.6.1. None.

6.0 Other Source Requirements [CDU, MEK-TOL, DHT-FUG, ISOM, UNIFINER, ADU, PL-FUG, and YNGL-FUG]

6.1. Limitations and Standards

- 6.1.1. Crude oil charge rate into the crude oil distillation unit shall not exceed 961,775 barrels per month and 9,617,750 barrels per year.

[45CSR13: Permit R13-2334, 6.1.1.]

- 6.1.2. Fugitive emissions of VOC's (MEK and Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 10.26 TPY. Fugitive emissions of HAPs (Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 5.09 TPY.

[45CSR13: Permit R13-2334, 6.1.2.]

- 6.1.3. The facility shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions:

- a. **Leak Definition for Valves.** The facility shall utilize an internal leak definition of 500 ppm VOCs for the Refinery valves, excluding pressure relief devices.
- b. **Leak Definition for Pumps.** The facility shall utilize an internal leak definition of 2000 ppm VOCs for the Refinery pumps.

[45CSR13: Permit R13-2334, 6.1.3.]

- 6.1.4. Fugitive emissions from the Diesel Hydrotreater [DHT-FUG], the Ammonia Destruction Unit [ADUFUG], the Platformer Expansion Unit [PL-FUG], and the Y-Grade NGL Unit [YNGL-FUG] shall not exceed the following:

Pollutant	DHT-FUG Fugitive Emissions	ADUFUG Fugitive Emissions	PL-FUG Fugitive Emissions	YNGL-FUG Fugitive Emissions
	ton/yr	ton/yr	ton/yr	ton/yr
VOC	13.20	0.34	0.60	0.94
Toluene	0.003	n/a	n/a	n/a
Ethyl Benzene	0.001	n/a	n/a	n/a
Xylene	0.04	n/a	n/a	n/a
Pentane	n/a	0.05	n/a	n/a
Hexane	n/a	0.02	0.04	0.03

[45CSR13: Permit R13-2334, 6.1.4.]

- 6.1.5. Fugitive emissions from the ISOM Unit shall not exceed 3.72 tpy VOC's and 0.85 tpy total HAP's.

[45CSR13: Permit R13-2334, 6.1.5.]

- 6.1.6. The permittee shall comply with the VOC equipment leak requirements of 40 CFR Part 60 Subpart VVa (as required by the applicability of 40 CFR Part 60, Subpart GGa) of affected facilities for which construction, reconstruction, or modification commenced after November 7, 2006 and Section 8.0 of this permit.

[45CSR13: Permit R13-2334, 6.1.6.]

6.2. Monitoring Requirements

6.2.1. None.

6.3. Testing Requirements

6.3.1. None.

6.4. Recordkeeping Requirements

6.4.1. To determine compliance with the crude oil charge rate limits set forth in Section 6.1.1., the permittee shall keep daily records along with monthly and yearly totals of the amount of crude oil charged to the crude oil distillation unit. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13: Permit R13-2334, 6.2.1.]

6.4.2. To determine compliance with VOC fugitive emission rate limits set forth in Sections 6.1.2., 6.1.4., 6.1.5., and the internal leak definitions set forth in Section 6.1.3, the permittee shall comply with the requirements of 40 CFR Part 60 Subpart VV and apply the following Leak Detection and Repair (LDAR) program enhancements:

Emission Estimates. The permittee may use an enhanced LDAR program for controlling and estimating emissions on a monthly and yearly basis for the Solvent Dewaxing Unit. The permittee may use EPA's Correlation Approach, published in EPA's Protocol for Equipment Leak Emission Estimates, with measured screening values and hours of operation to determine compliance with the emission limits.

[45CSR13: Permit R13-2334, 6.2.2.]

6.5. Reporting Requirements

6.5.1. None.

6.6. Compliance Plan

6.6.1. None.

7.0 Tank Requirements

7.1. Limitations and Standards

7.1.1. Storage tanks are limited to the raw material/ product type and throughput provided in the table below:

Tank ID No.	Raw Material/Product Type and Throughput (Mgal gallons per year)
4000, 4001, 4060, 4061, and 4072	crude oil (802,264.89 ~~,890~~ Mgal)
4062, 4063	crude oil and light crude oil w/vapor pressure up to 11.0 psia (306,600,000)
4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, 4052, 4053, 4070, and 4071	gasoline or ethanol (325,070,903 ~~,903~~)
4002, 4003, 4009, 4011, 4054, 4055, 4056, 4057, and 4073	heavy products or kerosene (406,459,76 ~~,760~~)
4007, 4008, 4010, 4017, 4018, 4019, 4020, 4021, 4022, 4023, 4024, 4025, 4026, 4027, 4028, 4029, 4030, 4031, 4032, 4033, 4034, 4035, 4036, 4037, 4038, 4039, 4040, 4041, 4042, 4043, 4044, 4045, 4046, 4047, 4048, 4051, 4103, and 4104	heavy products (609,920,249 ~~,249~~)
V-4002 and V-4003	Natural Gas Liquids

[45CSR13: Permit R13-2334, 7.1.1.]

7.1.2. Combined emissions from the tanks listed in section 7.1.1 shall not exceed the following:

Pollutant	Emission Rate	
	TPM	TPY
Total VOC	6.03	60.29
Benzene	0.09	0.85
Total HAP	0.69	6.86

[45CSR13: Permit R13-2334, 7.1.2.]

7.1.3. Fixed roof Tanks 4012 and 4013 shall be equipped with internal floating roofs to minimize emissions of VOC's.

[45CSR13: Permit R13-2334, 7.1.3.]

7.1.4. The following requirements apply to Tanks 4001, 4002, 4003, 4004, 4005, 4006, 4014, 4015, 4016:

- Each and every slotted guidepole that passes through the floating roof shall be equipped with one of the following: a pole float system; an alternate control technology that has an emission factor less than or equal to the emission factor for a pole float system; a pole sleeve system; an internal sleeve emission control system; a solid guidepole system; a flexible enclosure system; or
- In the alternative, the Permittee may elect to cover an external floating roof tank with a fixed roof mounted on the tank above the external floating roof, or remove the tank from the service storing liquids subject to NSPS Ka or Kb, modify the permit for that tank, and represent to the West Virginia Division of Air Quality that the tank will not be used to store certain petroleum liquids or volatile organic liquids.

- c. For systems that use a sliding cover, the sliding cover shall be in place over the slotted-guidepole opening in the floating roof at all times, except, when the sliding cover must be removed for access. If the control technology used includes a guidepole float, the float shall be floating within the guidepole at all times except when it must be removed for access to the stored liquid or when the tank is empty.
- d. The permittee shall visually inspect the deck fitting for the slotted guidepole at least once every ten (10) years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device has defects, or if a gap that is more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material.
- e. Tanks taken out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are taken out of service. Tanks taken out of service must have in place, prior to being put back into service, all controls necessary to remain below the emission limits set forth by the current version of permit R13-2334

[45CSR13: R13-2334, 7.1.4., 7.1.5.]

- 7.1.5. The following 40 CFR 60 Subpart K requirements apply to Tanks 4036, 4037, 4038, and 4039:

The owner or operator of any storage vessel to which 40 CFR Part 60 subpart K applies shall store petroleum liquids as follows: if the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

[40 CFR §60.112(a)(1) and 45CSR§16-4.1.; 45CSR13: Permit R13-2334, 7.1.6.]

- 7.1.6. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, 4046:

The owner or operator of each storage vessel to which 40 CFR Part 60 Subpart Ka applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

- 1. An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in 40 CFR §60.112a (a)(1)(ii)(D), the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
 - i. The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:
 - A. The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm² per meter of tank diameter (10.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

- B. The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).
 - C. One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.
 - D. There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
 - ii. The secondary seal is to meet the following requirements:
 - A. The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in 40 CFR §60.112a (a)(1)(ii)(B).
 - B. The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.
 - C. There are to be no holes, tears or other openings in the seal or seal fabric.
 - D. The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.
 - iii. Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in 40 CFR §60.112a (a)(1)(iv). Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.
 - iv. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.
- 2. A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set

to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

3. A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.
4. A system equivalent to those described in 40 CFR §60.112a (a)(1), (a)(2), or (a)(3) as provided in 40 CFR §60.114a.

[40 C.F.R. §60.112a(a) and 45CSR16]

7.1.7. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070 and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

- a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ 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 m³ but less than 151 m³ 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:
 1. A fixed roof in combination with an internal floating roof meeting the following specifications:
 - i. The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.
 - ii. Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:
 - A. A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.
 - B. Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.
 - C. A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

- iii. Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.
 - iv. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.
 - v. Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
 - vi. Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.
 - vii. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.
 - viii. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.
 - ix. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.
2. An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:
- i. Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.
 - A. The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in 40 CFR §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.
 - B. The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in 40 CFR §60.113b(b)(4).
 - ii. Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed

on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

- iii. The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
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 40 CFR 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 (40 CFR §60.18) of the General Provisions.
4. A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) above as provided in 40 CFR §60.114b.
- b. The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:
 1. A closed vent system and control device as specified in 40 CFR §60.112b(a)(3).
 2. A system equivalent to that described in paragraph (b)(1) as provided in 40 CFR §60.114b of this subpart.

[40 CFR §60.112b(a) and (b), 45CSR§16-4 .1., 45CSR13: Permit R13-2334, 7.1.7.]

- 7.1.8. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 60 Subpart Kb including but not limited to the following:
- a. Alternative means of compliance—(1) Option to comply with part 65. Owners or operators may choose to comply with 40 CFR Part 65, Subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR Part 65, Subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

[40 CFR §60.110b(e), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.8.]

- 7.1.9. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 65 Subparts C and G including but not limited to the following:

- a. Storage vessel requirements. The owner or operator expressly referenced to this subpart from Subpart C of this part shall comply with the following requirements, as applicable:

Route to a fuel gas system or process. Owners or operators subject to §65.42(b)(6) who route storage vessel emissions to a fuel gas system or to a process shall meet the requirements in §65.144 and the monitoring, recordkeeping, and reporting requirements referenced therein. No other provisions of this subpart apply to storage vessel emissions being routed to a fuel gas system or to a process.

[40 CFR §65.142(a)(3), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(a)]

- b. *Route to process or fuel gas system.* Route the emissions to a process or a fuel gas system as specified in §65.142(a)(3). Whenever the owner or operator bypasses the fuel gas system or process, the owner or operator shall comply with the recordkeeping requirement in §65.163(b)(3). Bypassing is permitted if the owner or operator complies with one or more of the following conditions:

- i. The liquid level in the storage vessel is not increased;
- ii. The emissions are routed through a closed vent system to a control device complying with paragraph (b)(4) or (5) of this section; or
- iii. The total aggregate amount of time during which the emissions bypass the fuel gas system or process during the calendar year without being routed to a control device, for all reasons (except startups/shutdowns/malfunctions or product changeovers of flexible operation units and periods when the storage vessel has been emptied and degassed), does not exceed 240 hours.

[40 CFR §65.42(b)(6), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(b)]

- c. Except during periods of startup, shutdown, and malfunction as specified in §65.3(a), the fuel gas system or process shall be operating at all times when regulated material emissions are routed to it.

[40 CFR §65.144(a)(1), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(c)]

- 7.1.10. You must meet each emission limit and management practice in Table 1 to 40 CFR 63 Subpart BBBBBB that applies to your gasoline storage tank.

If you own or operate ...	Then you must ...
2. A gasoline storage tank with a capacity of greater than or equal to 75 m ³ and not meeting any of the criteria specified in item 1 of this Table	(a) Reduce emissions of total organic HAP or TOC by 95 weight-percent with a closed vent system and control device, as specified in §60.112b(a)(3) of this chapter; or
	(b) Equip each internal floating roof gasoline storage tank (4012, 4013, and 4050) according to the requirements in §60.112b(a)(1) of this chapter, except for the secondary seal requirements under §60.112b(a)(1)(ii)(B) and the requirements in §60.112b(a)(1)(iv) through (ix) of this chapter; and
	(c) Equip each external floating roof gasoline storage tank (4004, 4005, 4006, 4014, 4015, 4016, and 4071) according to the requirements in §60.112b(a)(2) of this chapter, except that the requirements of §60.112b(a)(2)(ii) of this chapter shall only be required if such storage tank does not currently meet the requirements of §60.112b(a)(2)(i) of this chapter; or

If you own or operate ...	Then you must ...
	(d) Equip and operate each internal and external 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), and equip each external floating roof gasoline storage tank according to the requirements of §63.1063(a)(2) if such storage tank does not currently meet the requirements of §63.1063(a)(1).

[40 C.F.R. §63.11087(a); Table 1 to 40 C.F.R 63 Subpart BBBBBB, 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.2. Monitoring Requirements

- 7.2.1. Compliance with Section 7.1.4. may be determined by visual inspection by the Director or a duly authorized representative of the Director.

[45CSR13: Permit R13-2334, 7.2.1.]

- 7.2.2. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

The owner or operator of each storage vessel as specified in 40 CFR §60.112b(a) shall meet the requirements of paragraph a., b., or c. of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of 40 CFR §60.112b.

- a. After installing the control equipment required to meet 40 CFR §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:
 1. Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.
 2. For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in 40 CFR §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.
 3. For vessels equipped with a double-seal system as specified in 40 CFR §60.112b(a)(1)(ii)(B) :

- i. Visually inspect the vessel as specified in paragraph a.4. of this section at least every 5 years; or
 - ii. Visually inspect the vessel as specified in paragraph a.2. of this section.
- 4. Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs a.2. and a.3.ii. of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph a.3.i. of this section.
- 5. Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs a.1. and a.4. of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph a.4. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.
- b. After installing the control equipment required to meet 40 CFR §60.112b(a)(2) (external floating roof), the owner or operator shall:
 - 1. Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.
 - i. Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.
 - ii. Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.
 - iii. If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs b.1.i. and b.1.ii. of this section.
 - 2. Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

- i. Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - ii. Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.
 - iii. The total surface area of each gap described in paragraph b.2.ii. of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
3. Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph b.4. of this section.
4. Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 40 CFR §60.113b(b)(4) (i) and (ii).
5. Notify the Administrator 30 days in advance of any gap measurements required by paragraph b.1. of this section to afford the Administrator the opportunity to have an observer present.
6. Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.
 - i. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.
 - ii. For all the inspections required by paragraph b.6. of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph b.6. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.
- c. 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.

1. 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.
 - 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 40 CFR Part 60 subpart K, 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 816C 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).
 2. 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 c.1. of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.
 - d. The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in 40 CFR §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, 40 CFR §60.18 (e) and (f).
[40 C.F.R. §60.113b, 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.2.2.]
- 7.2.3. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, and 4046:
- a. Except as provided in 40 CFR §60.8(b) compliance with the standard prescribed in 40 CFR §60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in 40 CFR §60.114a.
 1. The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:
 - i. Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:
 - A. For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

- B. For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.
 - C. If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs 40 CFR §§60.113a(a)(1)(i)(A) and (a)(1)(i)(B).
 - D. Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by 40 CFR §60.113a(a)(1)(ii) and the calculation required by 40 CFR 60.113a(a)(1)(iii).
 - E. If either the seal gap calculated in accord with 40 CFR §60.113a (a)(1)(iii) or the measured maximum seal gap exceeds the limitations specified by 40 CFR §60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of 40 CFR §60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of 40 CFR §60.112a.
- ii. Determine gap widths in the primary and secondary seals individually by the following procedures:
 - A. Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - B. Measure seal gaps around the entire circumference of the tank in each place where a $\frac{1}{8}$ " diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.
 - C. The total surface area of each gap described in 40 CFR §60.113a (a)(1)(ii)(B) shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
 - iii. Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in 40 CFR §60.112a(a)(1)(i) and §60.112a(a)(1)(ii).
 - iv. Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.
- 2. The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

- i. Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.
- ii. The manufacturer's design specifications and estimated emission reduction capability of the system.
- iii. The operation and maintenance plan for the system.
- iv. Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

[40 CFR §60.113a and 45CSR16]

7.2.4. The following 40 CFR 60 Subpart Kb requirements apply to Tanks V-4002 and V-4003:

- (e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 - (1) For 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 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.
 - (2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - (i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
 - (ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.
 - (3) For other liquids, the vapor pressure:
 - (i) May be obtained from standard reference texts, or
 - (ii) Determined by ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17); or
 - (iii) Measured by an appropriate method approved by the Administrator; or
 - (iv) Calculated by an appropriate method approved by the Administrator.

[40 CFR §60.116b(e) and 45CSR16]

7.3. Testing Requirements

7.3.1. Each owner or operator subject to the emission standard in §63.11087 for gasoline storage tanks shall comply with the requirements in 40 C.F.R. §§63.11092(e)(1) through (3).

(1) If your gasoline storage tank is equipped with an internal floating roof, you must perform inspections of the floating roof system according to the requirements of 40 C.F.R. §60.113b(a) if you are complying with option 2(b) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB, or according to the requirements of 40 C.F.R. §63.1063(c)(1) if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB. **(4012, 4013, and 4050)**

(2) If your gasoline storage tank is equipped with an external floating roof, you must perform inspections of the floating roof system according to the requirements of 40 C.F.R. §60.113b(b) if you are complying with option 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB, or according to the requirements of 40 C.F.R. §63.1063(c)(2) if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB. **(4004, 4005, 4006, 4014, 4015, 4016, and 4071)**

[40 C.F.R. §63.11092(e); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.4. Recordkeeping Requirements

7.4.1. To determine compliance with the throughput limits set forth in Section 7.1.1. and the VOC emission limit set forth in Section 7.1.2., the permittee shall keep monthly records of throughput of each raw material/product for each tank. These records shall be kept individually, i.e. per tank. AP-42 emission factors for organic liquid storage tanks (Supp. D, Chapter 7.1), may be used to estimate yearly emissions.

[45CSR13: Permit R13-2334, 7.3.1., 45CSR§30-5.1.c.]

7.4.2. To determine compliance with the short-term and annual HAP emission limits set forth in Section 7.1.2., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of HAPs present in petroleum liquids processed and transported at the facility. The following equation shall be used to determine monthly and yearly emissions.

HAP Emissions (tpm or tpy) = [(Individual HAP %) x (Actual VOC emissions, obtained from section 7.4.1. (tpm or tpy))]/100

Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13: Permit R13-2334, 7.3.2., 45CSR§30-5.1.c.]

7.4.3. The following 40 CFR 60 Subpart K requirements apply to Tanks 4036, 4037, 4038, and 4039:

Except as provided in 40 CFR §60.113(d), the owner or operator subject to 40 CFR Part 60 subpart K shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

[40 CFR §60.113(a), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.3.]

7.4.4. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, and 4046:

- a. Except as provided in 40 CFR §§60.115a (d), the owner or operator subject to 40 CFR Part 60 Subpart Ka shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.
- b. Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
- c. The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

[40 CFR §§60.115a(a) through (c) and 45CSR16]

7.4.5. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

The owner or operator of each storage vessel as specified in 40 CFR §60.112b (a) shall keep records and furnish reports as required by 40 CFR §60.115b (a), (b), or (c) depending upon the control equipment installed to meet the requirements of 40 CFR §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by 40 CFR §60.115b (c) (1), for at least 2 years. The record required by 40 CFR §60.115b (c)(1) will be kept for the life of the control equipment.

- a. After installing control equipment in accordance with 40 CFR §60.112b (a) (1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.
 1. Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR §60.112b (a)(1) and 40 CFR §60.113b (a)(1). This report shall be an attachment to the notification required by 40 CFR §60.7 (a)(3).
 2. Keep a record of each inspection performed as required by 40 CFR §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).
 3. If any of the conditions described in 40 CFR §60.113b (a)(2) are detected during the annual visual inspection required by 40 CFR §60.113b (a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.
 4. After each inspection required by 40 CFR §60.113b (a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 40 CFR §60.113b (a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection.

The report shall identify the storage vessel and the reason it did not meet the specifications of 40 CFR §60.112b (a)(1) or 40 CFR §60.113b (a)(3) and list each repair made.

- b. After installing control equipment in accordance with 40 CFR §60.112b (a)(2) (external floating roof), the owner or operator shall meet the following requirements.
 1. Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR §60.112b (a)(2) and 40 CFR §60.113b (b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by 40 CFR §60.7(a)(3).
 2. Within 60 days of performing the seal gap measurements required by 40 CFR §60.113b (b)(1), furnish the Administrator with a report that contains:
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in 40 CFR §§60.113b (b)(2) and (b)(3).
 3. Keep a record of each gap measurement performed as required by 40 CFR §60.113b (b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in 40 CFR §§60.113b (b)(2) and (b)(3).
 4. After each seal gap measurement that detects gaps exceeding the limitations specified by 40 CFR §60.113b (b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in 40 CFR §60.115b (b)(2) and the date the vessel was emptied or the repairs made and date of repair.
- c. 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.
 1. A copy of the operating plan.
 2. A record of the measured values of the parameters monitored in accordance with 40 CFR §60.113b(c)(2).
- d. After installing a closed vent system and flare to comply with 40 CFR §60.112b, the owner or operator shall meet the following requirements.
 1. A report containing the measurements required by 40 CFR §§60.18 (f)(1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by 40 C.F.R. §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

2. Records shall be kept of all periods of operation during which the flare pilot flame is absent.
3. Semiannual reports of all periods recorded under 40 CFR §60.115b (d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

[40 CFR §60.115b, 45CSR§16-4.1.; 45CSR13: Permit R13-2334, 7.3.4.]

- 7.4.6. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, 4071, and 4073:
- a. The owner or operator shall keep copies of all records required by 40 CFR Part 60 Subpart Kb, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section 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 and an analysis showing the capacity of the storage vessel.
 - c. Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa 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.
 - d. Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.
 - e. Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 1. For 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 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.
 2. For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - i. Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference -- see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

- ii. The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.
- f. The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.
 - 1. Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.
 - 2. For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in 40 CFR §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:
 - i. ASTM D2879-83, 96, or 97 (incorporated by reference -- see 40 CFR §60.17); or
 - ii. ASTM D323-82 or 94 (incorporated by reference -- see 40 CFR §60.17); or
 - iii. As measured by an appropriate method as approved by the Administrator.
- g. The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of 40 CFR §60.112b or with emissions reductions equipment as specified in 40 CFR §65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[40 CFR §60.116b, 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.5.]

- 7.4.7. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 65 Subparts C and G including but not limited to the following:
- a. Bypass records for storage vessel emissions routed to a process or fuel gas system. An owner or operator who uses the bypass provisions of §65.144(a)(2) shall keep in a readily accessible location the following records:
 - i. The reason it was necessary to bypass the process equipment or fuel gas system;
 - ii. The duration of the period when the process equipment or fuel gas system was bypassed;
 - iii. Documentation or certification of compliance with the applicable provisions of §65.42(b)(6).

[40 CFR §65.163(b)(3), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(a)]

- b. Vessel dimensions and capacity. Each owner or operator of a storage vessel subject to this subpart shall keep readily accessible records showing the dimensions of the storage vessel and an analysis of the capacity of the storage vessel.

[40 CFR §65.47(b), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(b)]

- c. Regulated source and control equipment startup, shutdown and malfunction records. (1) Records of the occurrence and duration of each startup, shutdown, and malfunction of process equipment or of air pollution control equipment used to comply with this part during which excess emissions (as defined in §65.3(a)(4)) occur.

[40 CFR §65.163(c), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(c)]

- 7.4.8. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 60 Subpart A including but not limited to the following:

- a. Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

1. A notification of the date construction (or reconstruction as defined under 40 CFR §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

[40 CFR §60.7(a)(1), 45CSR§16-4.1]

- 7.4.9. Each owner or operator of a bulk gasoline terminal or pipeline breakout station whose storage vessels are subject to the provisions of this subpart shall keep records as specified in 40 C.F.R. §60.115b of this chapter if you are complying with options 2(a), 2(b), or 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBB, except records shall be kept for at least 5 years. If you are complying with the requirements of option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBB, you shall keep records as specified in 40 C.F.R. §63.1065.

[40 C.F.R. §63.11094(a); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.5. Reporting Requirements

- 7.5.1. Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:

- (1) For storage vessels, if you are complying with options 2(a), 2(b), or 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBB, the information specified in 40 C.F.R. §60.115b(a), 40 C.F.R. §60.115b(b), or 40 C.F.R. §60.115b(c), depending upon the control equipment installed, or, if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBB, the information specified in 40 C.F.R. §63.1066.

[40 C.F.R. §63.11095(a); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.6. Compliance Plan

- 7.6.1. None.

8.0 Equipment Leak Detection and Repair Requirements

8.1. Limitations and Standards

8.1.1. **Training.** The permittee shall implement the following training programs at the facility:

- a. For personnel newly-assigned to LDAR responsibilities, EWVI shall require LDAR training prior to each employee beginning such work;
- b. For all personnel assigned LDAR responsibilities, EWVI shall provide and require completion of annual LDAR training; and
- c. For all other Refinery operations and maintenance personnel (including contract personnel), EWVI shall provide and require completion of an initial training program that includes instruction on aspects of LDAR that are relevant to the person's duties. Refresher training in LDAR shall be performed on a three-year cycle.

[45CSR13: Permit R13-2334, 8.1.1., 45CSR§30-12.7]

8.1.2. **LDAR Personnel.** The permittee shall establish a program that will hold LDAR personnel accountable for LDAR performance. The permittee shall maintain a position within the facility responsible for LDAR management, with the authority to implement improvements.

[45CSR13: Permit R13-2334, 8.1.2., 45CSR§30-12.7]

8.1.3. **Internal Leak Definition for Valves and Pumps; Compressor Compliance.** The permittee shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions.

- a. Leak Definition for Valves. The permittee shall utilize an internal leak definition of 500 ppm VOCs for the valves at the facility, excluding pressure relief devices.
- b. Leak Definition for Pumps. The permittee shall utilize an internal leak definition of 2000 ppm VOCs for the pumps at the facility.

[45CSR13: Permit R13-2334, 8.1.3., 45CSR§30-12.7]

8.1.4. **First Attempt at Repairs on Valves.** The permittee shall make a "first attempt" at repair on any valve that has a reading greater than 200 ppm of VOCs, excluding control valves, pumps, and components that LDAR personnel are not authorized to repair. The permittee, or its designated contractor, however, shall re-monitor, within 5 business days, all valves that LDAR personnel attempted to repair. Unless the re-monitored leak rate is greater than the applicable leak definition, no further action will be necessary.

[45CSR13: Permit R13-2334, 8.1.4., 45CSR§30-12.7]

8.1.5. **Delay of Repair.** For any equipment for which the permittee is allowed, under the applicable regulations, to place on the "delay of repair" list for repair:

- a. For all equipment, the permittee shall:

1. Require sign-off by the unit supervisor or shift supervisor that the piece of equipment is technically infeasible to repair without a process unit shutdown, before the component is eligible for inclusion on the “delay of repair” list; and
2. Include equipment that is placed on the “delay of repair” list in the permittee’s regular LDAR monitoring.
- b. For valves: For valves, other than control valves, leaking at a rate of 10,000 ppm or greater, the permittee shall continue to use its “drill and tap” method for fixing such leaking valves, rather than placing the valve on the “delay of repair” list, unless the permittee can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner. After two unsuccessful attempts to repair a leaking valve through the drill and tap method, the permittee may place the leaking valve on its “delay of repair” list. If a new method develops for repairing such valves, the permittee will advise EPA prior to implementing such new method.
- c. For pumps: For pumps leaking at a rate of 2000 ppm or greater, the permittee shall undertake its best efforts to isolate and repair such pumps with a first attempt at fifteen (15) days.

[45CSR13: Permit R13-2334, 8.1.5., 45CSR§30-12.7]

- 8.1.6. a. 1. The provisions of 40 CFR Part 60 Subpart GGGa apply to affected facilities in petroleum refineries.
2. A compressor is an affected facility.
3. The group of all the equipment (defined in 40 CFR §60.591a) within a process unit is an affected facility.
- b. Any affected facility under 40 CFR §60.590a(a) that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of 40 CFR Part 60 Subpart GGGa.
- c. Addition or replacement of equipment (defined in 40 CFR §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under 40 CFR Part 60 Subpart GGGa.

[45CSR16, 40 CFR §§60.590a (a) through (c)]

- 8.1.7. a. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGGa shall comply with the requirements of 40 CFR §§60.482-1a to 60.482-10a as soon as practicable, but no later than 180 days after initial startup.
- b. For a given process unit, an owner or operator may elect to comply with the requirements of 40 CFR §60.592a (b)(1), (2), or (3) as an alternative to the requirements in 40 CFR §60.482-7a.
1. Comply with 40 CFR §60.483-1a.
 2. Comply with 40 CFR §60.483-2a.
 3. Comply with the Phase III provisions in 40 CFR §63.168, except an owner or operator may elect to follow the provisions in 40 CFR §60.482-7a (f) instead of 40 CFR §63.168 for any valve that is designated as being leakless.

- c. An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of 40 CFR §60.484a.
- d. Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 40 CFR §60.485a except as provided in 40 CFR §60.593a.
- e. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGa shall comply with the provisions of 40 CFR §§60.486a and 60.487a.

[45CSR16, 40 CFR §60.592a]

- 8.1.8. a. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGa may comply with the following exceptions to the provisions of 40 CFR Part 60 Subpart VVa.
- b. 1. Compressors in hydrogen service are exempt from the requirements of 40 CFR §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.
 - 2. Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260-73, 91, or 96, E168-67, 77, or 92, or E169-63, 77, or 93 (incorporated by reference as specified in 40 CFR §60.17) shall be used.
 - 3. i. An owner or operator may use engineering judgment rather than procedures in 40 CFR §60.593a (b)(2) to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in 40 CFR §60.593a (b)(2) shall be used to resolve the disagreement.
 - ii. If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in 40 CFR §60.593a (b)(2).
- c. Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from 40 CFR §§60.482-3a (a) through (e) and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §§60.482-3a (a) through (e) and (h).
- d. An owner or operator may use the following provision in addition to 40 CFR §60.485a (e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86-78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in 40 CFR §60.17).

- e. Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of 40 CFR §§60.482-2a and 60.482-7a.
- f. Open-ended valves or lines containing asphalt as defined in 40 CFR §60.591a are exempt from the requirements of 40 CFR §§60.482-6a (a) through (c).
- g. Connectors in gas/vapor or light liquid service are exempt from the requirements in 40 CFR §60.482-11a, provided the owner or operator complies with 40 CFR §60.482-8a for all connectors, not just those in heavy liquid service.

[45CSR16, 40 CFR §60.593a]

- 8.1.9. Any affected facility under 40 CFR §60.480a (a) that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of 40 CFR Part 60 Subpart VVa unless other permit requirements require more stringent requirements.

[45CSR13: R13-2334, 8.1.6., 45CSR16, 40 CFR §§60.480a (b)]

Standards: General

- 8.1.10. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall demonstrate compliance with the requirements of 40 CFR §§60.482-1a through 60.482-10a or 40 CFR §60.480a (e) for all equipment within 180 days of initial startup.
- b. Compliance with §§60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.
- c. 1. The permittee may request a determination of equivalence of a means of emission limitation to the requirements of 40 CFR §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in 40 CFR §60.484a.
2. If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of 40 CFR §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, or 60.482-10a, the permittee shall comply with the requirements of that determination.
- d. Equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in 40 C.F.R. §60.486a (e)(5).
- e. Equipment that the permittee designates as being in VOC service less than 300 hr/yr is excluded from the requirements of 40 CFR §§60.482-2a through 60.482-11a if it is identified as required in §60.486a (e) (6) and it meets any of the conditions specified in 40 CFR §§60.482-1a (e) (1) through (3).
- 1. The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.
 - 2. The equipment is in VOC service only during process malfunctions or other emergencies.

3. The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.
- f. 1. If a dedicated batch process unit operates less than 365 days during a year, the permittee may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in 40 CFR §§60.482-2a, 60.482-7a, and 60.483-2a

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually
25 to <50	Quarterly	Semiannually	Annually
50 to <75	Bimonthly	Three quarters	Semiannually
75 to 100	Monthly	Quarterly	Semiannually

2. Pumps and valves that are shared among two or more batch process units that are subject to 40 CFR Part 60 Subpart VVa may be monitored at the frequencies specified in 40 CFR §60.482-1a (f)(1), provided the operating time of all such process units is considered.
3. The monitoring frequencies specified in 40 CFR §60.482-1a (f)(1) are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. The permittee may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in 40 CFR §§60.482-1a (f)(3)(i) through (iv).
 - i. When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.
 - ii. When monitoring is conducted semiannually (i.e. , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.
 - iii. When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.
 - iv. When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.
- g. If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to 40 CFR Part 60 Subpart VVa, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to 40 CFR Part 60 Subpart VVa, the storage vessel is assigned to any process unit subject to 40 CFR Part 60 Subpart VV. If the predominant use of the storage vessel varies from year to year, then the permittee must estimate the predominant use initially and reassess every 3 years. The permittee must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

[45CSR16, 40 CFR §60.482-1a, 45CSR13: R13-2334, 8.1.6.]

Standards: Pumps in Light Liquid Service

- 8.1.11. a. 1. Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR §60.485a (b), except as provided in 40 CFR §§60.482-1a (c) and (f) and 40 CFR §§60.482-2a (d), (e), and (f). 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 40 CFR §60.482-1a (c) and 40 CFR §§60.482-2a (d), (e), and (f).
2. Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in 40 CFR §60.482-1a (f).
- b. 1. The instrument reading that defines a leak is specified in 40 CFR §§60.482-2a (b)(1)(i) and (ii).
- i. 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
- ii. 2,000 ppm or greater for all other pumps.
2. If there are indications of liquids dripping from the pump seal, the permittee shall follow the procedure specified in either 40 CFR §60.482-2a (b)(2)(i) or (ii). This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in 40 CFR § 60.482-2a (b)(1)(i) or (ii), whichever is applicable.
- i. Monitor the pump within 5 days as specified in 40 CFR § 60.485a (b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in 40 CFR § 60.482-2a (b)(1)(i) or (ii), whichever is applicable. The leak shall be repaired using the procedures in 40 CFR § 60.482-2a (c).
- ii. Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in 40 CFR § 60.482-2a (c) or by eliminating the visual indications of liquids dripping.
- c. 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in 40 CFR §§ 60.482-2a (c)(2)(i) and (ii), where practicable.
- i. Tightening the packing gland nuts;
- ii. Ensuring that the seal flush is operating at design pressure and temperature
- d. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of 40 CFR § 60.482-2a (a), provided the requirements specified in 40 CFR §§ 60.482-2a (d)(1) through (6) are met.
1. Each dual mechanical seal system is:

- i. Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or
 - ii. 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 40 CFR § 60.482-10a; or
 - iii. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
2. The barrier fluid system is in heavy liquid service or is not in VOC service.
3. Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.
4.
 - i. Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.
 - ii. If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the permittee shall follow the procedure specified in either 40 C.F.R. § 60.482-2a (d) (4) (ii) (A) or (B) prior to the next required inspection.
 - A. Monitor the pump within 5 days as specified in 40 CFR § 60.485a (b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
 - B. Designate the visual indications of liquids dripping as a leak.
5.
 - i. Each sensor as described in 40 CFR § 60.482-2a (d)(3) is checked daily or is equipped with an audible alarm.
 - ii. 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.
 - iii. If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in 40 CFR § 60.482-2a (d)(5)(ii), a leak is detected.
6.
 - i. When a leak is detected pursuant to 40 CFR § 60.482-2a (d)(4)(ii)(A), it shall be repaired as specified in 40 CFR § 60.482-2a (c).
 - ii. A leak detected pursuant to 40 CFR § 60.482-2a (d)(5)(iii) shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.
 - iii. A designated leak pursuant to 40 CFR § 60.482-2a (d)(4)(ii)(B) shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.
- e. Any pump that is designated, as described in 40 CFR §§ 60.486a (e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR §§ 60.482-2a (a), (c), and (d) if the pump:

1. Has no externally actuated shaft penetrating the pump housing;
 2. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 C.F.R. § 60.485a (c); and
 3. Is tested for compliance with 40 CFR § 60.482-2a (e)(2) initially upon designation, annually, and at other times requested by the Administrator.
- f. 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 or to a fuel gas system or to a control device that complies with the requirements of 40 CFR § 60.482-10a, it is exempt from 40 CFR §§ 60.482-2a (a) through (e).
- g. Any pump that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 40 CFR §§ 60.482-2a (a) and (d)(4) through (6) if:
1. The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 C.F.R. § 60.482-2a (a); and
 2. The owner or operator of the pump 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 repair of the equipment according to the procedures in 40 CFR § 60.482-2a (c) if a leak is detected.
- h. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of 40 CFR §§ 60.482-2a (a)(2) and (d)(4), and the daily requirements of 40 CFR § 60.482-2a (d)(5), provided that each pump is visually inspected as often as practicable and at least monthly.

[45CSR16, 40 CFR § 60.482-2a, 45CSR13, R13-2334, 8.1.6.]

Standards: Compressors

- 8.1.12. a. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR §§ 60.482-3a (h), (i), and (j).
- b. Each compressor seal system as required in 40 CFR § 60.482-3a (a) shall be:
1. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
 2. Equipped with a barrier fluid system 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 40 CFR § 60.482-10a; or

3. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. Each barrier fluid system as described in 40 CFR § 60.482-3a (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.
- e.
 1. Each sensor as required in 40 CFR § 60.482-3a (d) shall be checked daily or shall be equipped with an audible alarm.
 2. The permittee shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.
- f. If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under 40 CFR § 60.482-3a (e)(2), a leak is detected.
- g.
 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
 2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- h. A compressor is exempt from the requirements of 40 CFR §§ 60.482-3a (a) and (b), if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of 40 CFR § 60.482-10a, except as provided in paragraph (i) of this section.
- i. Any compressor that is designated, as described in 40 CFR §§ 60.486a (e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR §§ 60.482-3a (a) through (h) if the compressor:
 1. Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in 40 CFR § 60.485a (c); and
 2. Is tested for compliance with 40 CFR § 60.482-3a (i)(1) initially upon designation, annually, and at other times requested by the Administrator.
- j. Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of 40 CFR § 60.14 or 40 CFR § 60.15 is exempt from 40 CFR §§ 60.482-3a (a) through (e) and (h), provided the permittee demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §§ 60.482-3a (a) through (e) and (h).

[45CSR16, 40 CFR § 60.482-3a, 45CSR13: R13-2334, 8.1.6]

Standards: Pressure relief devices in gas/vapor service.

- 8.1.13. a. Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR § 60.485a (c).
- b. 1. After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR § 60.482-9a.
2. No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR § 60.485a (c).
- c. 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 40 CFR § 60.482-10a is exempted from the requirements of 40 CFR §§ 60.482-4a (a) and (b).
- d. 1. Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of 40 CFR §§ 60.482-4a (a) and (b), provided the permittee complies with the requirements in 40 CFR § 60.482-4a (d)(2).
2. After each pressure release, a new rupture disk shall be installed 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 40 CFR § 60.482-9a.

[45CSR16, 40 CFR § 60.482-4a, 45CSR13: R13-2334, 8.1.6.]

Standards: Sampling connection systems.

- 8.1.14. a. Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR § 60.482-5a (c).
- b. Each closed-purge, closed-loop, or closed-vent system as required in 40 CFR § 60.482-5a (a) shall comply with the requirements specified in 40 CFR §§ 60.482-5a (b)(1) through (4).
1. Gases displaced during filling of the sample container are not required to be collected or captured.
2. Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.
3. Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.
4. Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either 40 C.F.R. §§ 60.482-5a (b) (4) (i), (ii), (iii), or (iv).

- i. Return the purged process fluid directly to the process line.
- ii. Collect and recycle the purged process fluid to a process.
- iii. Capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR § 60.482-10a.
- iv. Collect, store, and transport the purged process fluid to any of the following systems or facilities:
 - A. A waste management unit as defined in 40 CFR § 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR Part 63 Subpart G, applicable to Group 1 wastewater streams;
 - B. A treatment, storage, or disposal facility subject to regulation under 40 CFR Part 262, 264, 265, or 266;
 - C. A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR Part 261;
 - D. A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR § 61.348 (a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR. § 61.343 through 40 CFR § 61.347; or
 - E. A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR Part 279 Subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR Part 261.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of 40 CFR §§ 60.482-5a (a) and (b).

[45CSR16, 40 CFR § 60.482-5a, 45CSR13: R13-2334, 8.1.6.]

Standards: Open-ended valves or lines.

- 8.1.15. a.
 - 1. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR §§ 60.482-6a (d) and (e).
 - 2. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

- c. 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 comply with 40 CFR § 60.482-6a (a) at all other times.
- d. 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 §§ 60.482-6a (a), (b), and (c).
- e. 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 40 CFR §§ 60.482-6a (a) through (c) are exempt from the requirements of 40 CFR §§ 60.482-6a (a) through (c).

[45CSR16, 40 CFR § 60.482-6a, 45CSR13, R13-2334, 8.1.6.]

Standards: Valves in gas/vapor service and in light liquid service.

- 8.1.16. a. 1. Each valve shall be monitored monthly to detect leaks by the methods specified in 40 CFR § 60.485a (b) and shall comply with 40 CFR §§ 60.482-7a (b) through (e), except as provided in 40 CFR §§ 60.482-7a (f), (g), and (h), 40 CFR §§ 60.482-1a (c) and (f), and 40 CFR §§ 60.483-1a and 60.483-2a.
2. A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to 40 CFR § 60.482-7a (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in 40 CFR §§ 60.482-7a (f), (g), and (h), 40 CFR § 60.482-1a (c), and 40 CFR §§ 60.483-1a and 60.483-2a.
- i. Monitor the valve as in 40 CFR § 60.482-7a (a)(1). The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.
 - ii. If the existing valves in the process unit are monitored in accordance with 40 CFR § 60.483-1a or 40 CFR § 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in 40 C.F.R. § 60.483-2a (b) (5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.
- b. If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- c. 1. i. Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.
- ii. As an alternative to monitoring all of the valves in the first month of a quarter, the permittee may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The permittee must keep records of the valves assigned to each subgroup.
2. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

- d.
 - 1. When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR § 60.482-9a.
 - 2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- e. First attempts at repair include, but are not limited to, the following best practices where practicable:
 - 1. Tightening of bonnet bolts;
 - 2. Replacement of bonnet bolts;
 - 3. Tightening of packing gland nuts;
 - 4. Injection of lubricant into lubricated packing.
- f. Any valve that is designated, as described in 40 CFR § 60.486a (e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR § 60.482-7a (a) if the valve:
 - 1. Has no external actuating mechanism in contact with the process fluid,
 - 2. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR § 60.485a (c), and
 - 3. Is tested for compliance with 40 CFR § 60.482-7a (f)(2) initially upon designation, annually, and at other times requested by the Administrator.
- g. Any valve that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 40 CFR § 60.482-7a (a) if:
 - 1. The permittee of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR § 60.482-7a (a), and
 - 2. The permittee of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.
- h. Any valve that is designated, as described in 40 CFR § 60.486a (f)(2), as a difficult-to-monitor valve is exempt from the requirements of 40 CFR § 60.482-7a (a) if:
 - 1. The permittee of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
 - 2. The process unit within which the valve is located either:
 - i. Becomes an affected facility through 40 CFR § 60.14 or 40 CFR § 60.15 and was constructed on or before January 5, 1981; or

- ii. Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the permittee.
- 3. The permittee of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[45CSR16, 40 CFR § 60.482-7a, 45CSR13: R13-2334, 8.1.6.]

Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

- 8.1.17. a. If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the permittee shall follow either one of the following procedures:
 - 1. The permittee shall monitor the equipment within 5 days by the method specified in 40 CFR § 60.485a (b) and shall comply with the requirements of 40 CFR §§ 60.482-8a (b) through (d).
 - 2. The permittee shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c.
 - 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
 - 2. The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- d. First attempts at repair include, but are not limited to, the best practices described under 40 CFR §§ 60.482-2a (c)(2) and 60.482-7a (e).

[45CSR16, 40 CFR § 60.482-8a, 45CSR13: R13-2334, 8.1.6.]

Standards: Delay of repair.

- 8.1.18. a. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment 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.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves and connectors will be allowed if:
 - 1. 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

2. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR § 60.482-10a.
- d. Delay of repair for pumps will be allowed if:
 1. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
 2. Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.
- e. 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.
- f. When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

[45CSR16, 40 CFR § 60.482-9a, 45CSR13: R13-2334, 8.1.6.]

Standards: Closed vent systems and control devices.

- 8.1.19. a. Owners or operators of closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VVa shall comply with the provisions of 40 CFR § 60.482-10a.
- b. Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.
- c. Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816°C.
- d. Flares used to comply with 40 CFR Part 60 Subpart VVa shall comply with the requirements of 40 CFR § 60.18.
- e. Owners or operators of control devices used to comply with the provisions of 40 CFR Part 60 Subpart VVa shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.
- f. Except as provided in 40 CFR §§ 60.482-10a (i) through (k), each closed vent system shall be inspected according to the procedures and schedule specified in 40 CFR §§ 60.482-10a (f) (1) and (2).
 1. If the vapor collection system or closed vent system is constructed of hard-piping, the permittee shall comply with the requirements specified in 40 CFR §§ 60.482-10a (f)(1)(i) and (ii):
 - i. Conduct an initial inspection according to the procedures in 40 CFR § 60.485a (b); and

- ii. Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.
- 2. If the vapor collection system or closed vent system is constructed of ductwork, the permittee shall:
 - i. Conduct an initial inspection according to the procedures in 40 CFR § 60.485a (b); and
 - ii. Conduct annual inspections according to the procedures in 40 CFR § 60.485a (b).
- g. Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in 40 CFR § 60.482-10a (h).
 - 1. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
 - 2. Repair shall be completed no later than 15 calendar days after the leak is detected.
- h. Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the permittee determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.
- i. If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2).
- j. Any parts of the closed vent system that are designated, as described in 40 CFR § 60.482-10a (l)(1), as unsafe to inspect are exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR §§ 60.482-10a (j)(1) and (2):
 - 1. The permittee 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 40 CFR § 60.482-10a (f)(1)(i) or (f)(2); and
 - 2. The permittee has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.
- k. Any parts of the closed vent system that are designated, as described in 40 CFR § 60.482-10a (l)(2), as difficult to inspect are exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR §§ 60.482-10a (k)(1) through (3):
 - 1. The permittee determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and
 - 2. The process unit within which the closed vent system is located becomes an affected facility through 40 CFR § 60.14 or 60.15, or the permittee designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and
 - 3. The permittee has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

- l. The permittee shall record the information specified in 40 CFR §§ 60.482-10a (l)(1) through (5).
 1. Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.
 2. Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.
 3. For each inspection during which a leak is detected, a record of the information specified in 40 CFR § 60.486a (c).
 4. For each inspection conducted in accordance with 40 CFR § 60.485a (b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
 5. For each visual inspection conducted in accordance with 40 CFR § 60.482-10a (f)(1)(ii) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- m. Closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VVa shall be operated at all times when emissions may be vented to them.

[45CSR16, 40 CFR § 60.482-10a, 45CSR13: R13-2334, 8.1.6.]

- 8.1.20. a. The owner or operator shall 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 owner or operator is required to monitor only those connectors involved in the process change.
- b. Except as allowed in 40 CFR § 60.482-1a (c), 40 CFR § 60.482-10a, or as specified in 40 CFR § 60.482-11a (e), the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in 40 CFR §§ 60.482-11a (a) and (b) (3).
 1. The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, 40 CFR § 60.485a (c).
 2. If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.
 3. The owner or operator shall perform monitoring, subsequent to the initial monitoring required in 40 CFR § 60.482-11a (a), as specified in 40 CFR §§ 60.482-11a (b)(3)(i) through (iii), and shall comply with the requirements of 40 CFR §§ 60.482-11a (b)(3)(iv) and (v). The required period in which monitoring must be conducted shall be determined from 40 CFR §§ 60.482-11a (b)(3)(i) through (iii) using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in 40 CFR §§ 60.482-11a (c).

- i. If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).
 - ii. If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
 - iii. If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in 40 CFR § 60.482-11a (b)(3)(iii)(A) and either 40 CFR § 60.482-11a (b)(3)(iii)(B) or (b)(3)(iii)(C), as appropriate.
 - A. An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
 - B. If the percent of leaking connectors calculated from the monitoring results in 40 CFR § 60.482-11a (b)(3)(iii)(A) is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to 40 CFR § 60.482-11a (b)(3), based on the percent of leaking connectors within the total monitored connectors.
 - C. If the percent of leaking connectors calculated from the monitoring results in 40 CFR § 60.482-11a (b)(3)(iii)(A) is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.
 - iv. If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
 - v. The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.
- c. For use in determining the monitoring frequency, as specified in 40 CFR §§ 60.482-11a (a) and (b)(3), the percent leaking connectors as used in 40 CFR §§ 60.482-11a (a) and (b)(3) shall be calculated by using the following equation:

$$\%C_L = C_L / C_t \times 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in 40 CFR §§ 60.482-11a (a) and (b)(3)(i) through (iii).

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in 40 CFR § 60.485a (b).

C_t = Total number of monitored connectors in the process unit or affected facility.

- d. When a leak is detected pursuant to 40 CFR §§ 60.482-11a (a) and (b), it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.
- e. Any connector that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor connector is exempt from the requirements of 40 CFR §§ 60.482-11a (a) and (b) if:
 - 1. The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR §§ 60.482-11a (a) and (b); and
 - 2. The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in 40 CFR § 60.482-11a (d) if a leak is detected.
- f. *Inaccessible, ceramic, or ceramic-lined connectors.*
 - 1. 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 (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of 40 CFR §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in 40 CFR §§ 60.482-11a (f)(1)(i) through (vi), as applicable:
 - i. Buried;
 - ii. Insulated in a manner that prevents access to the connector by a monitor probe;
 - iii. Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
 - iv. 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;
 - v. Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
 - vi. 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.
 - 2. If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

- g. Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

[45CSR16, 40 CFR § 60.482-11a, 45CSR13: R13-2334, 8.1.6.]

- 8.1.21. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in 40 CFR Part 60 Subpart VVa.
- b. Determination of equivalence to the equipment, design, and operational requirements of 40 CFR Part 60 Subpart VVa will be evaluated by the following guidelines:
 - 1. Each permittee applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.
 - 2. The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.
 - 3. The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.
- c. Determination of equivalence to the required work practices in 40 CFR Part 60 Subpart VVa will be evaluated by the following guidelines:
 - 1. Each permittee applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.
 - 2. For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.
 - 3. For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.
 - 4. Each permittee applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.
 - 5. The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in 40 CFR § 60.484a (c)(4).
 - 6. The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

- d. The permittee may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.
- e.
 - 1. After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.
 - 2. After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.
 - 3. Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111 (h) (1) of the CAA.
- f.
 - 1. Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of 40 CFR Part 60 Subpart VVa.
 - 2. The Administrator will make an equivalence determination according to the provisions of 40 CFR §§ 60.484a (b), (c), (d), and (e).

[45CSR16, 40 CFR § 60.484a, 45CSR13: R13-2334, 8.1.6.]

8.2. Monitoring Requirements

- 8.2.1. **Reporting, Recording, Tracking, Repairing and Re-monitoring Leaks of Valves and Pumps.** The permittee shall record, track, repair and re-monitor all leaks in excess of the internal leak definitions.
[45CSR13: Permit R13-2334, 8.2.1., 45CSR§30-12.7]

8.2.2. LDAR Monitoring Frequency

- i. Pumps. The permittee shall monitor pumps on a monthly basis.
- ii. Valves. The permittee shall monitor valves -- other than difficult to monitor or unsafe to monitor valves -- on a quarterly basis.

[45CSR13: Permit R13-2334, 8.2.2., 45CSR§30-12.7]

8.2.3. Calibration/Calibration Drift Assessment

- i. Calibration. The permittee shall conduct all calibrations of LDAR monitoring equipment using methane as the calibration gas, in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21.
- ii. Calibration Drift Assessment. The permittee shall conduct calibration drift assessments of LDAR monitoring equipment at the end of each monitoring shift, at a minimum. The permittee shall conduct the calibration drift assessment using, at a minimum, a 500 ppm calibration gas. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous

calibration, the permittee shall re-monitor all valves that were monitored since the last calibration that had a reading greater than 100 ppm and shall re-monitor all pumps that were monitored since the last calibration that had a reading greater than 500 ppm.

[45CSR13: Permit R13-2334, 8.2.3., 45CSR§30-12.7]

8.2.4. **LDAR Audits.** The permittee shall implement at the facility the Refinery audits set forth in the following paragraphs to ensure compliance with all applicable LDAR requirements. The LDAR audits shall include, but not be limited to, comparative monitoring, records review, tagging, data management, and observation of the LDAR technicians' calibration and monitoring techniques.

- i. Third-Party Audits. The permittee shall retain a contractor(s) to perform a third-party audit of the refinery's LDAR program at least once every four years.
- ii. Internal Audits. The permittee shall conduct internal audits of the LDAR program. An internal audit of the refinery shall be held every four years.
- iii. To ensure that an audit at the refinery occurs every two years, third-party and internal audits shall be separated by two years.
- iv. Alternative. As an alternative to the internal audit, the permittee may elect to retain third-parties to undertake the internal audit, provided that an audit of the facility occurs every two (2) years.

[45CSR13: Permit R13-2334, 8.2.4., 45CSR§30-12.7]

8.2.5. If the results of any of the audits conducted at the facility identify any areas of non-compliance, the permittee shall implement, as soon as practicable, all steps necessary to correct the area(s) of noncompliance, and to prevent, to the extent practicable, a recurrence of the cause of the non-compliance. The permittee shall retain the audit reports generated during the audits and shall maintain a written record of the corrective actions taken at the facility in response to any deficiencies identified in any audits.

[45CSR13: Permit R13-2334, 8.2.4., 45CSR§30-12.7]

8.3. Testing Requirements

- 8.3.1. For affected facilities subject to the standards in 40 CFR §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a, the permit shall determine compliance with the standards according to the test methods and procedures provided in §60.485a.
 - a. In conducting the performance tests required in 40 CFR § 60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in 40 CFR § 60.8 (b).
 - b. The permittee shall determine compliance with the standards in 40 CFR §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:
 1. Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of 40 CFR Part 60 Appendix A-7. The following calibration gases shall be used:

- i. Zero air (less than 10 ppm of hydrocarbon in air); and
 - ii. A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the permittee need not calibrate the scales that will not be used during that day's monitoring.
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 40 CFR Part 60 Appendix A-7, 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) (7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration 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 initial calibration value, 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 initial calibration value, 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.
- c. The permittee shall determine compliance with the no-detectable-emission standards in 40 CFR §§ 60.482-2a (e), 60.482-3a (i), 60.482-4a, 60.482-7a (f), and 60.482-10a (e) as follows:
 1. The requirements of 40 CFR § 60.485a (b) shall apply.
 2. Method 21 of 40 CFR Part 60 Appendix A-7 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.
- d. The permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:
 1. Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see 40 CFR § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
 2. Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

3. Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, 40 CFR §§ 60.485a (d)(1) and (2) shall be used to resolve the disagreement.
- e. The permittee shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:
 1. The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see 40 CFR § 60.17) shall be used to determine the vapor pressures.
 2. The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.
 3. The fluid is a liquid at operating conditions.
- f. Samples used in conjunction with 40 CFR §§ 60.485a (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.
- g. The permittee shall determine compliance with the standards of flares as follows:
 1. Method 22 of 40 CFR Part 60 Appendix A-7 shall be used to determine visible emissions.
 2. A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.
 3. The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m⁴/(MJ-sec) (metric units) = 0.087 ft⁴/(Btu-sec) (English units).

4. The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component “i,” ppm

H_i = net heat of combustion of sample component “i” at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

5. Method 18 of 40 CFR Part 60 Appendix A-6 or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see 40 C.F.R. § 60.17) shall be used to determine the concentration of sample component “i.”
6. ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see 40 CFR § 60.17) shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.
7. Method 2, 2A, 2C, or 2D of 40 CFR Part 60 Appendix A-7, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.
- h. The permittee shall determine compliance with 40 CFR § 60.483-1a or 40 CFR § 60.483-2a as follows:
 1. The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L/V_T) \times 100$$

Where:

$\%V_L$ = Percent leaking valves.
 V_L = Number of valves found leaking.
 V_T = The sum of the total number of valves monitored.

2. The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
3. The number of valves leaking shall include valves for which repair has been delayed.
4. Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
5. If the process unit has been subdivided in accordance with 40 CFR § 60.482-7a (c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
6. The total number of valves monitored does not include a valve monitored to verify repair.

[45CSR16, 40 CFR § 60.485a, 45CSR13: R13-2334, 8.3.1.]

8.4. Recordkeeping Requirements

- 8.4.1. **Adding New Valves and Pumps.** The permittee shall establish a tracking program for maintenance records (e.g., a Management of Change program) to ensure that valves and pumps added to the facility during maintenance and construction are integrated into the LDAR program.

[45CSR13: Permit R13-2334, 8.4.1., 45CSR§30-12.7]

8.4.2. When a leak is detected, the following requirements apply:

- i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- ii. The identification on a valve may be removed after it has been monitored for 2 successive months and no leak has been detected during those 2 months.
- iii. The identification on equipment, except on a valve, may be removed after it has been repaired.

[40 CFR § 60.486a(b), 45CSR13: Permit R13-2334, 8.4.2., 45CSR§30-12.7]

8.4.3. When a leak has been detected, the following information shall be recorded in a log and 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 10,000” if the maximum instrument reading measured after each repair attempt is equal to or greater than 10,000 ppm.
- v. “Repair delayed” and 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.

[40 CFR § 60.486a(c), 45CSR13: Permit R13-2334, 8.4.3., 45CSR§30-12.7]

8.4.4. The following information shall be recorded in a log that is kept in a readily accessible location:

- i. A list of identification numbers.
- ii. A list of identification numbers for equipment that are designated for no detectable emissions. This list shall be signed by the owner or operator.
- iii. A list of equipment identification numbers for pressure relief valves.
- iv. The dates of each compliance test.
- v. The background level measured during each compliance test.

- vi. The maximum instrument reading measured at the equipment during each compliance test.
- vii. A list of identification numbers for equipment in vacuum service.
- viii. A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr, a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

[40 CFR § 60.486a(e), 45CSR13: Permit R13-2334, 8.4.3., 45CSR§30-12.7]

- ix. For all valves and pumps designated as unsafe-to-monitor or difficult-to-monitor:
 - a. A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.
 - b. 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.

[40 CFR § 60.486a(f), 45CSR13: Permit R13-2334, 8.4.4.(xi.), 45CSR§30-12.7]

- 8.4.5. a.
 - 1. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall comply with the recordkeeping requirements of 40 CFR § 60.486a.
 - 2. The permittee of more than one affected facility subject to the provisions of 40 CFR Part 60 Subpart VVa may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
 - 3. The permittee shall record the information specified in 40 CFR §§ 60.486a (a)(3)(i) through (v) for each monitoring event required by 40 CFR §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.
 - i. Monitoring instrument identification.
 - ii. Operator identification.
 - iii. Equipment identification.
 - iv. Date of monitoring.
 - v. Instrument reading.
- b. When each leak is detected as specified in 40 CFR §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:
 - 1. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

2. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7a (c) and no leak has been detected during those 2 months.
 3. The identification on a connector may be removed after it has been monitored as specified in § 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
 4. The identification on equipment, except on a valve or connector, may be removed after it has been repaired.
- c. When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall 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, except when indications of liquids dripping from a pump are designated as a leak.
 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. Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.
 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 permittee (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.
- d. The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10a shall be recorded and kept in a readily accessible location:
1. Detailed schematics, design specifications, and piping and instrumentation diagrams.
 2. The dates and descriptions of any changes in the design specifications.
 3. A description of the parameter or parameters monitored, as required in § 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

4. Periods when the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
5. Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.
- e. The following information pertaining to all equipment subject to the requirements in §§ 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:
 1. A list of identification numbers for equipment subject to the requirements of 40 CFR Part 60 Subpart VVa.
 2.
 - i. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR §§ 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
 - ii. The designation of equipment as subject to the requirements of § 60.482-2a(e), § 60.482-3a(i), or § 60.482-7a(f) shall be signed by the permittee. Alternatively, the permittee may establish a mechanism with their permitting authority that satisfies this requirement.
 3. A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4a.
 4.
 - i. The dates of each compliance test as required in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
 - ii. The background level measured during each compliance test.
 - iii. The maximum instrument reading measured at the equipment during each compliance test.
 5. A list of identification numbers for equipment in vacuum service.
 6. A list of identification numbers for equipment that the permittee designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
 7. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
 8. Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and § 60.485a(b).
 - i. Date of calibration and initials of operator performing the calibration.
 - ii. Calibration gas cylinder identification, certification date, and certified concentration.
 - iii. Instrument scale(s) used.

- iv. 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 of this part.
 - v. Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
 - vi. If the permittee makes their own calibration gas, a description of the procedure used.
- 9. The connector monitoring schedule for each process unit as specified in § 60.482-11a (b)(3) (v).
- 10. Records of each release from a pressure relief device subject to § 60.482-4a.
- f. The following information pertaining to all valves subject to the requirements of 40 CFR §§ 60.482-7a (g) and (h), all pumps subject to the requirements of 40 CFR § 60.482-2a (g), and all connectors subject to the requirements of 40 CFR § 60.482-11a (e) shall be recorded in a log that is kept in a readily accessible location:
 - 1. 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.
 - 2. 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.
- g. The following information shall be recorded for valves complying with 40 CFR § 60.483-2a:
 - 1. A schedule of monitoring.
 - 2. The percent of valves found leaking during each monitoring period.
- h. The following information shall be recorded in a log that is kept in a readily accessible location:
 - 1. Design criterion required in 40 CFR §§ 60.482-2a (d)(5) and 60.482-3a (e)(2) and explanation of the design criterion; and
 - 2. Any changes to this criterion and the reasons for the changes.
- i. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR § 60.480a (d):
 - 1. An analysis demonstrating the design capacity of the affected facility,
 - 2. A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
 - 3. An analysis demonstrating that equipment is not in VOC service.

- j. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.
- k. The provisions of 40 CFR §§ 60.7(b) and (d) do not apply to affected facilities subject to 40 CFR Part 40 Subpart VVa.

[45CSR16, 40 CFR § 60.486a, 45CSR13: R13-2334, 8.4.5.]

8.5. Reporting Requirements

8.5.1. Electronic Monitoring, Storing, and Reporting of LDAR Data

- i. Electronic Storing and Reporting of LDAR Data. The facility will maintain an electronic database (e.g., EXCEL spreadsheet) for storing and reporting LDAR data. The electronic database shall include data identifying the date and time of the monitored event, and the operator and instrument used in the monitored event.
- ii. Electronic Data Collection During LDAR Monitoring and Transfer Thereafter. The permittee shall use data loggers and/or electronic data collection devices during all LDAR monitoring. The permittee, or its designated contractor, shall use its/their best efforts to transfer, by the end of the next business day, electronic data from electronic data logging devices to the electronic database listed above. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp. The permittee may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken), and shall record, at a minimum, the identification of the technician undertaking the monitoring, the date, and the identification of the monitoring equipment. The permittee shall use its best efforts to transfer any manually recorded monitoring data to the electronic database within seven days of monitoring.

[45CSR13: Permit R13-2334, 8.5.1., 45CSR§30-12.7]

- 8.5.2. **QA/QC of LDAR Data** - The permittee shall ensure that monitoring data provided to the permittee by its contractors is reviewed for QA/QC before the contractor submits the data to the permittee. At least once per calendar quarter, the permittee shall perform QA/QC of the contractor's monitoring data which shall include, but not be limited to, number of components monitored per technician, time between monitoring events, and abnormal data patterns.

[45CSR13: Permit R13-2334, 8.5.2., 45CSR§30-12.7]

- 8.5.3. The permittee shall submit semiannual reports to the Administrator beginning six months after the initial startup date. All semiannual reports shall include the following information:

- i. Process unit identification.
- ii. For each month during the semiannual reporting period,
 - a. Number of valves for which leaks were detected.
 - b. Number of valves for which leaks were not repaired.
 - c. Number of pumps for which leaks were detected.

- d. Number of pumps for which leaks were not repaired.
 - e. Number of compressors for which leaks were detected.
 - f. Number of compressors for which leaks were not repaired.
 - g. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - iv. Revisions to items reported in initial report if changes have occurred since the initial report or subsequent revisions to the initial report.

[40 CFR § 60.487a(c), 45CSR13: Permit R13-2334, 8.5.3., 45CSR§30-12.7]

- 8.5.4. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.
- b. The initial semiannual report to the Administrator shall include the following information:
- 1. Process unit identification.
 - 2. Number of valves subject to the requirements of 40 CFR § 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of 40 CFR § 60.482-7a (f).
 - 3. Number of pumps subject to the requirements of 40 CFR § 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of 40 CFR § 60.482-2a (e) and those pumps complying with 40 CFR § 60.482-2a (f).
 - 4. Number of compressors subject to the requirements of 40 CFR § 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of 40 CFR § 60.482-3a (i) and those compressors complying with 40 CFR § 60.482-3a (h).
 - 5. Number of connectors subject to the requirements of 40 CFR § 60.482-11a.
- c. All semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR § 60.486a:
- 1. Process unit identification.
 - 2. For each month during the semiannual reporting period,
 - i. Number of valves for which leaks were detected as described in 40 CFR § 60.482-7a (b) or § 60.483-2a,
 - ii. Number of valves for which leaks were not repaired as required in 40 CFR § 60.482-7a (d)(1),

- iii. Number of pumps for which leaks were detected as described in 40 CFR § 60.482-2a (b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
 - iv. Number of pumps for which leaks were not repaired as required in 40 CFR §§ 60.482-2a(c)(1) and (d)(6),
 - v. Number of compressors for which leaks were detected as described in 40 CFR § 60.482-3a (f),
 - vi. Number of compressors for which leaks were not repaired as required in 40 CFR § 60.482-3a (g) (1),
 - vii. Number of connectors for which leaks were detected as described in 40 CFR § 60.482-11a (b)
 - viii. Number of connectors for which leaks were not repaired as required in 40 CFR § 60.482-11a (d), and
 - ix. [Reserved]
 - x. [Reserved]
 - xi. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- 3. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - 4. Revisions to items reported according to 40 CFR § 60.487a (b) if changes have occurred since the initial report or subsequent revisions to the initial report.
- d. The permittee electing to comply with the provisions of 40 CFR §§ 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.
 - e. The permittee shall report the results of all performance tests in accordance with 40 CFR § 60.8 of the General Provisions. The provisions of 40 CFR § 60.8 (d) do not apply to affected facilities subject to the provisions of 40 CFR Part 60 Subpart VVa except that the permittee must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.
 - f. The requirements of 40 CFR §§ 60.487a (a) through (c) remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of 40 CFR §§ 60.487a (a) through (c), provided that they comply with the requirements established by the state.
- [45CSR13: R13-2334, 8.5.4., 45CSR16, 40 CFR § 60.487a]

8.6. Compliance Plan

- 8.6.1. None.

9.0 Equipment Leaks Requirements [VOC Emissions from Petroleum Refinery Wastewater Systems - 40 CFR Part 60 Subpart QQQ]

9.1. Limitations and Standards

- 9.1.1. a. Each owner or operator subject to the provisions of this subpart shall comply with the requirements of 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.
- b. Compliance with 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.696.
- ~~c.~~—1. Stormwater sewer systems are not subject to the requirements of this subpart.
2. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.
3. Non-contact cooling water systems are not subject to the requirements of this subpart.
4. An owner or operator shall demonstrate compliance with the exclusions in paragraphs c.1., 2., and 3. of this section as provided in 40 CFR § 60.697 (h), (i), and (j).

[40 CFR § 60.692-1(a), (b), and (d), 45CSR16, 45CSR13: Permit R13-2334, 9.1.1.]

9.1.2. Individual drain systems.

- a. 1. Each drain shall be equipped with water seal controls.
2. Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
3. Each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.
4. Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in 40 CFR § 60.692-6.
- b. 1. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
2. 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.
3. Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

4. If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in 40 CFR § 60.692-6.
- c.
 1. 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.
 2. The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.
 3. Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in 40 CFR § 60.692-6.
- d. Except as provided in paragraph e. of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987, shall be exempt from the provisions of this section.
- e. Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

[40 CFR § 60.692-2, 45CSR16, 45CSR13: Permit R13-2334, 9.1.2.]

9.1.3. Oil-water separators.

- a. Each oil-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 following specifications, except as provided in paragraph c. of this section or in 40 CFR § 60.693-2.
 1. The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
 2. The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
 3. If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
 4. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.
 5. When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.
- b. Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements

in paragraph a. of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of 40 CFR § 60.692-5.

- c. Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in 40 CFR §§ 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, Subparts K, Ka, or Kb are not subject to the requirements of this section.
- d. Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of 40 CFR Part 60, Subpart QQQ. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph a. of this section.
- e. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph a. of this section, and not paragraph b. of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

[40 CFR § 60.692-3 (a), (b), (d), (e), and (f), 45CSR16, 45CSR13: Permit R13-2334, 9.1.3.]

9.1.4. Alternative standards for oil-water separators.

- a. An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.
 - 1. Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.
 - i. The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.
 - A. A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.
 - B. The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.
 - C. The total gap area between the primary seal and the separator wall shall not exceed 67 cm²/m (3.2 in.²/ft) of separator wall perimeter.
 - ii. The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.
 - A. The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

- B. The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm²/m (0.32 in.²/ft) of separator wall perimeter.
- iii. The maximum gap width and total gap area shall be determined by the methods and procedures specified in 40 CFR § 60.696(d).
 - A. Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.
 - B. Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.
- iv. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs a.1.i. and ii. of this section.
- 2. Except as provided in paragraph a.4. of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.
- 3. The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).
- 4. The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.
- 5.
 - i. Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.
 - ii. When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.
- b. An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph a. of this section.
- c. For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of 40 CFR § 60.692-3(a) shall be installed.
- d. Except as provided in paragraph c. of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of 40 CFR §§ 60.692-3 or 60.694 applicable to the same facilities.

[40 CFR § 60.693-2, 45CSR 16, 45CSR13: Permit R13-2334, 9.1.4.]

9.1.5. Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of 40 CFR §§ 60.692-2 and 60.692-3.

[40 CFR § 60.692-4, 45CSR16, 45CSR13: Permit R13-2334, 9.1.5.]

9.1.6. Closed vent systems and control devices.

- a. Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.
- b. Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.
- c.
 1. Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR § 60.696.
 2. Closed vent systems shall be purged to direct vapor to the control device.
 3. A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.
 4. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.
 5. When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR § 60.692-6.

[40 CFR §§ 60.692-5(b), (d), and (e), 45CSR16, 45CSR13: Permit R13-2334, 9.1.6.]

9.1.7. Delay of repair.

- a. 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.
- b. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

[40 CFR § 60.692-6, 45CSR16, 45CSR13: Permit R13-2334, 9.1.7.]

9.2. Monitoring Requirements

- 9.2.1. Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

- a. Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

[40 CFR § 60.695(a)(3)(ii), 45CSR16, 45CSR13: Permit R13-2334, 9.2.1.]

9.3. Testing Requirements

- 9.3.1. Before using any equipment installed in compliance with the requirements of 40 CFR § 60.692-2, § 60.692-3, § 60.692-4, § 60.692-5, or § 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

[40 CFR § 60.696(a), 45CSR16, 45CSR13: Permit R13-2334, 9.3.1.]

- 9.3.2. The owner or operator of each source that is equipped with a closed vent system and control device as required in 40 CFR § 60.692-5 (other than a flare) is exempt from § 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

- a. Zero air (less than 10 ppm of hydrocarbon in air), and
- b. A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

[40 CFR § 60.696(b), 45CSR16, 45CSR13: Permit R13-2334, 9.3.2.]

9.4. Recordkeeping Requirements

- 9.4.1. Each owner or operator of a facility subject to the provisions of this subpart shall comply with the record keeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

[40 CFR § 60.697(a), 45CSR16, 45CSR13: Permit R13-2334, 9.4.1.]

- 9.4.2. a. For individual drain systems subject to 40 CFR § 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

b. For junction boxes subject to 40 § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

c. For sewer lines subject to 40 CFR §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(b), 45CSR16, 45CSR13: Permit R13-2334, 9.4.2.]

9.4.3. For oil-water separators subject to 40 CFR § 60.692-3, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-3(a) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(c), 45CSR16, 45CSR13: Permit R13-2334, 9.4.3.]

9.4.4. For closed vent systems subject to 40 CFR § 60.692-5 and completely closed drain systems subject to 40 CFR § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-5(e) during which detectable emissions are measured, or a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(d), 45CSR16, 45CSR13: Permit R13-2334, 9.4.4.]

9.4.5. a. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

b. The reason for the delay as specified in 40 CFR § 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

c. The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

d. The date of successful repair or corrective action shall be recorded.

[40 CFR § 60.697(e), 45CSR16, 45CSR13: Permit R13-2334, 9.4.5.]

9.4.6. a. A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

b. The following information pertaining to the design specifications shall be kept.

i. Detailed schematics, and piping and instrumentation diagrams.

ii. The dates and descriptions of any changes in the design specifications.

c. The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with

a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

- ii. For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.
- iii. Dates of startup and shutdown of the closed vent system and control devices required in 40 CFR § 60.692 shall be recorded and kept for 2 years after the information is recorded.
- iv. The dates of each measurement of detectable emissions required in 40 CFR §§ 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.
- v. The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.
- vi. The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.
- vii. Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

[40 CFR § 60.697(f), 45CSR16, 45CSR13: Permit R13-2334, 9.4.6.]

- 9.4.7. For stormwater sewer systems subject to the exclusion in 40 CFR § 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

[40 CFR § 60.697(h), 45CSR16, 45CSR13: Permit R13-2334, 9.4.7.]

- 9.4.8. For ancillary equipment subject to the exclusion in 40 CFR § 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

[40 CFR § 60.697(i), 45CSR16, 45CSR13: Permit R13-2334, 9.4.8.]

9.4.9. For oil-water separators subject to 40 CFR § 60.693-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.693-2(a)(1)(iii)(A) and (B); and shall be maintained for the time periods specified in paragraphs a. and b. below.

- a. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.
- b. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(B), two years after the information is recorded.

[40 CFR § 60.697(k), 45CSR16, 45CSR13: Permit R13-2334, 9.4.9.]

9.5. Reporting Requirements

9.5.1. Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

[40 CFR § 60.698(b)(1), 45CSR16, 45CSR13: Permit R13-2334, 9.5.1.]

9.5.2. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.

[40 CFR § 60.698(c), 45CSR16, 45CSR13: Permit R13-2334, 9.5.2.]

9.5.3. As applicable, a report shall be submitted semiannually to the Administrator that indicates:

Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in § 60.695(a)(3)(ii).

[40 CFR §§ 60.698(d)(3) and (d)(3)(ii), 45CSR16, 45CSR13: Permit R13-2334, 9.5.3.]

9.5.4. If compliance with the provisions of this subpart is delayed pursuant to 40 CFR § 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

[40 CFR § 60.698(e), 45CSR16, 45CSR13: Permit R13-2334, 9.5.4.]

9.6. Compliance Plan

9.6.1. None.

10.0 Benzene Waste Operations Requirements from 40 CFR Part 61 Subpart FF

HAPs Emission Standards. The permitted facility shall comply with all applicable provisions of 45CSR34, which, by incorporation, subjects the facility to the provisions of 40 CFR 61 Subpart FF - National Emission Standard for Benzene Waste Operations, provided, however, that compliance with any more stringent limitation set forth under Conditions 5.1.6., 6.1.2. and 7.1.1. of this permit shall also be demonstrated.

[45CSR13: Permit R13-2334, Section 10.0.]

10.1. Limitations and Standards

10.1.1. An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of 40 CFR § 61.342 (b) and (c). The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

- a. Wastes that are exempted from control under 40 C.F.R. §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
- b. The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.
- c. Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of 40 C.F.R. §§ 61.342(c) through (h). If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
- d. The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in 40 C.F.R. § 61.355(c)(1)(i) (A) through (C).

[40 CFR § 61.342(a), 45CSR34, 45CSR13: Permit R13-2334, 10.1.1.]

10.2. Monitoring Requirements

10.2.1. Compliance with 40 CFR part 61 subpart FF will be determined by review of facility records and results from tests and inspections using methods and procedures specified in Sections 10.3.1. through 10.3.3. of this permit.

[40 CFR § 61.342(g), 45CSR34, 45CSR13: Permit R13-2334, 10.2.1.]

10.3. Testing Requirements

10.3.1. An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

- a. For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in 40 CFR § 61.342(a), the owner or operator shall:
 1. Determine the annual waste quantity for each waste stream using the procedures specified in Section 10.3.2. of this permit.
 2. Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in Section 10.3.3. of this permit.
 3. Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.
- b. Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to Section 10.3.2.b. of this permit.
- c. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:
 1. Comply with the record keeping requirements of 40 CFR § 61.356 and reporting requirements of 40 CFR § 61.357; and
 2. Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.
- d. The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in Section 10.3.2.b. of this permit, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with Sections 10.3.1. through 10.3.3. of this permit. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

[40 CFR § 61.355(a), 45CSR34, 45CSR13: Permit R13-2334, 10.3.1.]

10.3.2. For purposes of the calculation required by Section 10.3.1. of this permit, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in Sections 10.3.2.a. and b. of this permit, by one of the methods given in Sections 10.3.2. c. through e. of this permit.

- a. The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

- b. The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in Section 10.3.1.a.3. of this permit for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under 40 CFR § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.
- c. Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility.
- d. Use the maximum design capacity of the waste management unit; or
- e. Use measurements that are representative of maximum waste generation rates.

[40 CFR § 61.355(b), 45CSR34, 45CSR13: Permit R13-2334, 10.3.2.]

10.3.3. For the purposes of the calculation required by 40 CFR §§ 61.355(a), an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in Section 10.3.3.a. of this permit using either of the methods given in Sections 10.3.3.b. and c. of this permit.

- a. The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:
 - 1. The determination shall be made at the point of waste generation except for the specific cases given in Sections 10.3.3.a.1.A and B. of this permit.
 - A. The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.
 - B. The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in Sections 10.3.3.b. or c. of this permit. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in Section 10.3.1.a.3. of this permit for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.
 - 2. Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.
 - 3. Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination -- to reduce the benzene concentration.

4. The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in Sections 10.3.3.a.1.A. and B. of this permit.
5. For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.
- b. *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under Section 10.3.3.c. of this permit shall be used to resolve the disagreement.
- c. Measurements of the benzene concentration in the waste stream in accordance with the procedures listed in 40 CFR § 61.355(c)(3).

[40 CFR § 61.355(c), 45CSR34, 45CSR13: Permit R13-2334, 10.3.3.]

10.4. Recordkeeping Requirements

- 10.4.1. Each owner or operator of a facility subject to the provisions of 40 CFR Part 61, subpart FF shall comply with the following record keeping requirements. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.
[40 CFR § 61.356(a), 45CSR34, 45CSR13: Permit R13-2334, 10.4.1.]
- 10.4.2. Each owner or operator shall maintain records that identify each waste stream at the facility subject to 40 CFR Part 61, subpart FF, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition, the owner or operator shall maintain the following records:
 - a. For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
 - b. For each waste stream exempt from 40 CFR § 61.342(c)(1) in accordance with 40 CFR § 61.342(c)(3), the records shall include:
 1. All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute, or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with 40 CFR § 61.342(c)(3)(i), or

2. All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with 40 CFR § 61.342(c)(3)(ii).
- c. For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with 40 CFR § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with 40 CFR § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with 40 CFR § 61.355(a)(1)(iii) of this section.

[40 CFR § 61.356(b), 45CSR34, 45CSR13: Permit R13-2334, 10.4.2.]

10.5. Reporting Requirements

- 10.5.1. Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to 40 CFR § 61.342 and is determined by the procedures specified in 40 CFR § 61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:
 - a. Total annual benzene quantity from facility waste determined in accordance with 40 CFR § 61.355(a) of this subpart.
 - b. A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.
 - c. For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:
 1. Whether or not the water content of the waste stream is greater than 10 percent;
 2. Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;
 3. Annual waste quantity for the waste stream;
 4. Range of benzene concentrations for the waste stream;
 5. Annual average flow-weighted benzene concentration for the waste stream; and
 6. Annual benzene quantity for the waste stream.

- d. The information required in Sections 10.5.1.a., b., and c. of this Permit should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in 40 CFR § 61.10(a).

[40 CFR § 61.357(a), 45CSR34, 45CSR13: Permit R13-2334, 10.5.1.]

- 10.5.2. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in Section 10.5.1.a. through c. of this permit. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by Section 10.5.1.a. through c. is not changed in the following year, the owner or operator may submit a statement to that effect.

[40 CFR § 61.357(c), 45CSR34, 45CSR13: Permit R13-2334, 10.5.2.]

10.6. Compliance Plan

- 10.6.1. None.

11.0 ~~Internal Combustion Engines~~ (Emergency Generators and Firewater Pump Engines) Requirements [FWPUMP1 and FWPUMP2, CEG01]

Commented [FT71]: Added as requested.

11.1. Limitations and Standards

11.1.1. What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions? (*For the fire pumps engines identified as FWPUMP1 and FWPUMP2.*)

If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d of 40 CFR 63 subpart ZZZZ that apply to you.

You must meet the following requirements, except during periods of startup. During periods of startup you must comply with Condition 11.2.1.b.

- Change oil and filter every 500 hours of operation or annually, whichever comes first; (Sources have the option to utilize an oil analysis program as described in Condition 11.2.1.c. in order to extend the specified oil change requirement.)
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

[45CSR34, 40 CFR §63.6603(a) and Table 2d ~~(4-1)~~; 45CSR13: Permit R13-2334, 11.1.1.c. 2]

Commented [FT72]: Changed back to (1)

11.1.2. What are my general requirements for complying with this subpart? (*For the fire pumps engines identified as FWPUMP1 and FWPUMP2.*)

- You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.
- At all times you 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. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. 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 §63.6605]

11.1.3. The engines for the fire pumps identified as FWPUMP1 and FWPUMP2 shall be operated and maintained in accordance with the following requirements.

- ~~Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for more than 50 hours per calendar year as described in 40 CFR §§63.6640(f)(1) through (4), for these engines are prohibited. Firepump engines FWPUMP1 and FWPUMP2 shall not operate more than 500 hours each per year. Compliance with this limit shall be based on a rolling 12 month total.~~

Commented [CG73]: Delete this new Section and revert back to original. These fire pumps are not designated as emergency. Instead, these fire pumps meet the RICE MACT requirements for non-emergency engines. This avoids the annual hours limit, resettable hour meter, etc. In addition, the existing 500 hours per year limit should remain.

Commented [FT74R73]: The added requirements for emergency engines have been deleted and the original requirements have been restored.

1. There is no time limit on the use of these emergency stationary engines during emergency situations.
 2. The permittee may operate each emergency stationary engine for the purpose specified in 40 CFR §60.4243(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by the following paragraph counts as part of the 100 hours per calendar year allowed by this paragraph.
 3. Each emergency stationary engine 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.
 4. Each emergency stationary engine 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 the above paragraph. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving, 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.
- b. Each engine shall be equipped with a non-resettable hour meter.
- c. Each engine must use diesel fuel that meets the requirements in Condition 11.1.5. of this permit.

[45CSR34, 40 CFR §§63.6640(f), (f)(1), (f)(2), (f)(4), §63.6625(f), §63.6604(b); 45CSR13: Permit R13-2334, 11.1.1.a., 11.1.1.d. and 11.1.1.e.]

11.1.4. The following conditions and requirements are specific to the engine for generator set identified as COGEN (CEG01):

- a. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for more than 50 hours per calendar year as described in 40 CFR §§60.4211(f)(1) through (3), for the engine are prohibited. Emergency operation/situations is defined when electric power from the local utility is interrupted from the facility.
1. There is no time limit on the use of the emergency stationary engine during emergency situations.
 2. The permittee may operate the emergency stationary engine for the purpose specified in 40 CFR §60.4243(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by the following paragraph counts as part of the 100 hours per calendar year allowed by this paragraph.

The emergency stationary engine 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.
 3. The emergency stationary engine 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 the above paragraph. 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, 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.

- b. The generator set shall be equipped with an engine or engine configuration that has been certified by the manufacturer to comply with either 40 CFR §60.4202(a)(2) or 40 CFR Part 60.
- c. The permittee shall operate and maintain the engine of the generator set according to the manufacturer's emission-related written instructions.
- d. The permittee shall only change those emission-related settings of the engine that are permitted by the manufacturer.
- e. The maximum nameplate power output of the engine for each generator set shall not be greater as listed in Table 1.0 of this permit.
- f. The engine shall be equipped with a non-resettable hour meter.
- g. The engine must use diesel fuel that meets the requirements in Condition 11.1.5. of this permit.
- h. The engine for CEG01 shall be a model year 2023 or later.
- i. You must meet the requirements of 40 CFR part 1068, as they apply to you.

[45CSR16; 40 CFR §60.4211(a), §60.4211(f); 45CSR13: Permit R13-2334, 11.1.2.]

- 11.1.5. Diesel fuel used by each engine for the generator set or firewater pump shall have a maximum sulfur content no greater than 15 ppm (ultra-low sulfur diesel) and with either a minimum centane index of 40 or a maximum aromatic content of 35 volume percent. Diesel meeting the specifications of Nonroad diesel under 40 CFR §80.510(b) is equivalent.

[45CSR16; 45CSR34; 40 CFR §60.4207(b), §1090.305 §63.6604(b); 45CSR13: Permit R13-2334, 11.1.3.]

- 11.1.6. The engine for generator set identified as COGEN (CEG01) must comply with the emission standards in 40 CFR §60.4202(a)(2) for all pollutants (i.e., the certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I for all pollutants and the smoke standards as specified in 40 CFR §1039).

[45CSR16; 40 CFR §60.4205(b)]

- 11.1.7. The engine for generator set identified as COGEN (CEG01) must meet the emission standards of 40 CFR §60.4205 over the entire life of the engine.

[45CSR16; 40 CFR §60.4206]

- 11.1.8. The certified engine for generator set identified as COGEN (CEG01) must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR §60.411(g). If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance pursuant to 40 CFR §60.4211(g) as follows:

You 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, you 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 you change emission-related settings in a way that is not permitted by the manufacturer. You 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(c), §60.4211(g) and (g)(3)]

11.2. Monitoring Requirements

11.2.1. What are my monitoring, installation, collection, operation, and maintenance requirements? *(For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)*

- a. If you own or operate an existing non-emergency, non- or black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [45CSR13: Permit R13-2334, 11.1.4.]
- b. If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Table 2d to 40 CFR subpart ZZZZ apply.
- c. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in Condition 11.1.1., you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in Condition 11.1.1. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[45CSR34, 40 CFR §63.6625(e), (e)(3.4), (h), and (i); 45CSR13: Permit R13-2334, 11.1.1.b.]

11.2.2. How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements? *(For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)*

- a. You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in 40 CFR 63 subpart ZZZZ, Table 2d that apply to you according to methods specified in 40 CFR 63 subpart ZZZZ, Table 6 (same as Condition 11.2.1.a.)

Commented [CG75]: Original condition should remain. Fire pumps are designated as non-emergency.

Commented [FT76R75]: Deleted the revisions and reverted back to the original requirements.

- b. You must report each instance in which you did not meet each emission limitation or operating limitation in 40 CFR 63 part ZZZZ, Table 2d that apply to you. These instances are deviations from the emission and operating limitations in this subpart.

[45CSR34, 40 CFR §§63.6640(a), (b) and Table 6(9)]

- 11.2.3. ~~For the purpose of demonstrating compliance with the hours of operation limit in Condition 11.1.3.a. for Emission Units FWPUMP1 and FWPUMP2 and Condition 11.1.4.a. for Emission Unit CEG01, the permittee shall record the number of hours each engine operated during the calendar month and the reason for such operation. For emergency operations, the permittee must document what is classified as the emergency for each emergency operation. The permittee shall maintain a calendar total of hours operated in non-emergency and emergency situations on a calendar year basis. Such records shall be maintained in accordance with Condition 3.4.2. For the purposes of determining compliance with 11.1.3., the permittee shall monitor and record the number of hours per month that fire water pump engines FWPUMP1 and FWPUMP2 operate.~~
[45CSR13: Permit R13-2334, 11.2.1.]

Commented [FT77]: Separated the fire pump requirements from the emergency generator requirements which basically restores the original requirements for the fire pump engines.

11.3. Testing Requirements

- 11.3.1. None.

11.4. Recordkeeping Requirements

11.4.1. What records must I keep?

- a. For the fire pumps engines identified as FWPUMP1 and FWPUMP2: If you must comply with the emission and operating limitations, you must keep the records described in paragraphs a.1. through a.4., and b.1.
1. A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).
 2. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
 3. Records of all required maintenance performed on the air pollution control and monitoring equipment.
 4. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition 11.1.2.b., including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
- b. For the fire pumps engines identified as FWPUMP1 and FWPUMP2 and the generator set engine identified as COGEN (CEG01): The permittee ~~You~~ must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's ~~your own~~ maintenance plan for each RICE. ~~if you own or operate any of the following stationary RICE; [45CSR13: Permit R13-2334, 11.2.2.]~~
1. ~~An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.~~
- c. For the fire pumps engines identified as FWPUMP1 and FWPUMP2: If the stationary RICE does not

meet the standards applicable to non-emergency engines, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

[45CSR34, 40 CFR §§63.6655(a), (e) and (e)(3), (f) and (f)(2); 45CSR13: Permit R13-2334, 11.2.2.]

11.4.2. **In what form and how long must I keep my records?** (For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)

Your records must be in a form suitable and readily available for expeditious review according to 40 CFR §63.10(b)(1). As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[45CSR34, 40 CFR §§63.6660]

11.5. Reporting Requirements

11.5.1. ~~None.~~ For the fire pumps engines identified as FWPUMP1 and FWPUMP2, you must report all deviations as defined in 40 CFR 63 Subpart ZZZZ in the semiannual monitoring report required by condition 3.5.6. You must also report each instance in which you did not meet the requirements in Table 8 to 40 CFR 63 Subpart ZZZZ that apply to you
[45CSR34; 40 CFR §63.6640(e), §63.6650(f)]

11.5.2. If the engine for generator set identified as COGEN (CEG01) operates for the purpose specified in 40 CFR §60.4211(f)(3)(i), you must submit an annual report according to the following requirements

a. The report must contain the following information:

1. Company name and address where the engine is located.
2. Date of the report and beginning and ending dates of the reporting period.
3. Engine site rating and model year.
4. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
5. 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. 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 this subpart 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. Submit the annual report electronically according to 40 CFR §60.4214(g).

Commented [CG78]: Remove reporting requirement. Fire pumps are non-emergency.

Commented [FT79R78]: These reporting requirements have been removed.

Commented [CG80]: Remove new reporting section. No reporting requirements. Engines are less than 300 hp and are non-emergency.

Commented [FT81R80]: The requirements of 40 CFR 63.6640(e) are applicable to existing CI Rice less than 500 Hp at an area source of HAPs. The requirements of 40 CFR 63.6650(f) is applicable to an affected source that has obtained a Title V operating permit. Therefore these requirements have not been removed.

[\[45CSR16; 40 CFR §60.4214\(d\)\]](#)

11.6. Compliance Plan

11.6.1. None.

APPENDIX A

45CSR2 & 45CSR10 Monitoring Plan

Commented [CG82]: An updated plan will be submitted to DEP for incorporation as part of the Title V Renewal.

Ergon - West Virginia, Inc.

9995 Ohio River Blvd, Post Office Box 356
Newell, West Virginia 26050-0356

Ms. Carrie McCumbers
WVDEP—Division of Air Quality
601 57th Street SE
Charleston, West Virginia 25304

RE: Monitoring Plan under 45 CSR 2 and 45 CSR 10

Dear Ms McCumbers:

Ergon West Virginia, Inc. (EWWI) is presenting the following monitoring plan as required under Title 45 of the Code of State Regulations (CSR) Series 2 and Series 10 (45 CSR 2 and 45 CSR10). The allowable emission rates for all of these units have been registered as part of air permit (R13-2334).

Boiler C:

This boiler is permitted to combust a combination of natural gas and refinery fuel gas (RFG) and has a design heat capacity (DHC) less than 100 MMBtu/hr.

Regulation 2

- **Opacity:** The combination of natural gas/RFG combusted within the boiler is very similar to natural gas. There is no probable cause that would indicate that opacity would be generated from the combustion of EWWI's RFG. Since natural gas combustion is exempt from visibility testing, EWWI requests that no visible emission testing be required when combusting RFG.
- **Weight Emission Testing:** Under permit R13-2334, EWWI has monthly and yearly limits on particulate (PM) emissions. EWWI documents PM emissions from Boilers A and B utilizing fuel usage records and regulatory limits. To demonstrate that these units operate will below allowable limits, EWWI proposes the following monitoring plan and request that no stack testing be required for the boilers.

Refinery fuel gas: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that significant particulate emissions from the combustion of EWWI's RFG, which is very similar to natural gas, would be generated.

- As required under §45-2-8.3.c, EWWI maintains records of the startup and shutdown of the boiler, and the quantity of fuel gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, this boiler cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boiler. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Boiler A and B:

These boilers combust a combination of natural gas and refinery fuel gas and have DHCs greater than 100 MMBtu/hr, but less than 250MMBtu/hr.

Regulation 2

- Opacity: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that opacity would be generated from the combustion of EWVI's RFG. Since natural gas combustion is exempt from visibility testing, EWVI requests that no visible emission testing be required when combusting RFG.
- Weight Emission Testing: Under permit R13-2334, EWVI has monthly and yearly limits on particulate (PM) emissions. EWVI documents PM emissions from Boilers A and B utilizing fuel usage records and regulatory limits. To demonstrate that these units operate will below allowable limits, EWVI proposes the following monitoring plan and request that no stack testing be required for the boilers.

Refinery fuel gas: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that significant particulate emissions from the combustion of EWVI's RFG, which is very similar to natural gas, would be generated.

- As required under §45-2-8.3.c, and §45-2A-7, EWVI maintains records of the startup and shutdown of the boilers, and the quantity of RFG combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, these boilers cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boilers. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Combustion Sources – H101R, H102R, H201, H501R, H500's, H600's, H701, H901

These units are process heaters and combust natural gas/refinery fuel gas combination fuel as their primary fuel. All of these units have DHCs between 10-100 MMBtu/hr, except H201, which has a DHC less than 10 MMBtu/hr.

Regulation 2

- **Opacity:** These heaters meet the requirements set forth in this regulation so therefore visible emission testing is indicated per §45-2-3.2. However, these units are exempt from testing and monitoring requirements since the DHCs of these units are less than 100 MMBtu/hr, per §45-2-8.4.c.
- **Weight Emission Testing:** Heater H201 is exempt from testing, monitoring, recordkeeping and reporting requirements as stipulated in §45-2-11, other than of course those requirements stated within the existing permit. The remaining heaters are less than 100 MMBtu/hr and therefore, are exempt from the periodic testing requirements in §45-2-8.1.a and the monitoring requirements in §45-2-8.2.
- As required in §45-2-8.3.c, and §45-2A-7, EWVI maintains records of the startup and shutdown of the heaters and the quantity of RFG and natural gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, these heaters cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boilers. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Combustion Sources-H441, H1101

The DHC for H441 is just over 10 MMBtu/hr and the DHC for H1101 is between 10-100 MMBtu/hr. These two heaters are fired with natural gas only.

Regulation 2

- As per the regulation §45-2-8.4.b and the guidance listed in §452A-3.1.a, since these heaters burn only natural gas, they are exempt from visible emission testing and weight emissions testing requirements.
- As required under §45-2-8.3.c, EWVI maintains records of the startup and shutdown of these heaters, and the quantity of natural gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10A-10.3, since these units combust only natural gas, they are exempt from the requirements in §45-10-8, which includes testing, monitoring, recordkeeping and reporting.

Manufacturing Process Sources-Main Flare

The flare is an emergency control device for the manufacturing process sources of the entire refinery.

Regulation 2

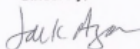
- Regulation 2 does not apply since this regulation only applies to indirect heat exchangers.

Regulation 10

- As indicated in §45-10A-5.2.b, process sources that utilize a flare as a control device are exempt from compliance testing requirements. Also EWWI has a flare gas recovery system on its flare.

If you have any questions or require additional information, please contact me at (304) 387-7046.

Sincerely,



Jack Azar
ESHT Manager

APPENDIX B

Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance

Appendix A of R13-2334 (See 40 CFR §60.7(d))

Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO₂/NO_x/TRS/H₂S/CO/O₂)

Reporting period dates: From _____ to _____

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period¹

<u>Emission Data summary</u>	<u>CMS Performance Summary</u>
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown	a. Monitor equipment malfunctions
b. Control equipment problems	b. Non-Monitor equipment malfunctions
c. Process problems	c. Quality assurance calibration
d. Other known causes	d. Other known causes
e. Unknown causes	e. Unknown causes
2. Total duration of excess emission	2. Total CMS Downtime
3. Total duration of excess emissions × (100) [Total source operating time] % ²	3. [Total CMS Downtime] x (100) [Total source operating time] % ²

¹For gases, record all times in hours.

²For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process, or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name:

Signature:

Title:

Date:



Tipane, Frederick <frederick.tipane@wv.gov>

Re: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Tipane, Frederick <frederick.tipane@wv.gov>

Thu, Aug 21, 2025 at 5:09 PM

To: Evan Gay <Evan.Gay@ergon.com>

Cc: Greir Merchant <Greir.Merchant@ergon.com>, Caleb Gingerich <caleb.gingerich@trinityconsultants.com>, George Mesing <gmesing@trinityconsultants.com>, Dan Shaw <Dan.Shaw@ergon.com>

Evan,

Attached are my responses to Ergon's Pre-Draft Title V permit comments. Most of the comments dealt with the requirements in the Pre-draft R13-2334AK permit. Ed and I worked together to address the R13 issues so that the Title V requirements will be the same.

Once R13-2334AK is issued, I will finalize the Title V permit and start the public notice period and EPA's comment period before the end of next week.

Should have any questions let me know.

Thanks,
Fred

On Mon, Aug 18, 2025 at 10:15 AM Evan Gay <Evan.Gay@ergon.com> wrote:

Good morning, Fred –

Please find our comments attached. Let me know if you have any questions at all.

As always, we appreciate your work on this.

Evan

Evan Gay

Sr Environmental Engineer

Corporate Environmental – Projects Team

Ergon, Inc.

M 601-337-1591

P 601-933-3097



From: Tipane, Frederick <frederick.tipane@wv.gov>

Sent: Wednesday, July 30, 2025 2:35 PM

To: Evan Gay <Evan.Gay@ergon.com>; Greir Merchant <Greir.Merchant@ergon.com>

Subject: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

Good afternoon Evan and Greir,

Please find attached for your review the Pre-Draft Permit R30-02900008-2021(SM01, MM03) and Fact Sheet for Ergon West Virginia's Newell Refinery. I have included the Pre-Draft revisions of R13-2334AK and highlighted them in yellow. I will finalize the requirements once R13-2334AK is issued. Since my deadline for issuance is rapidly approaching, I'm requesting that you submit any comments or questions regarding the permit and/or fact sheet to me as soon as possible but no later than August 18, 2025.

Please feel free to contact me with any questions or concerns or if you wish to discuss any issues..

Regards,

Fred

--



Frederick Tipane

Division of Air Quality

601 57th Street, SE

Charleston, WV 25304

(304) 414-1910

frederick.tipane@wv.gov

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Pre-DPPermit03,04 R30-02900008-2021(SM01, MM03)_R1.docx
9662K



Tipane, Frederick <frederick.tipane@wv.gov>

RE: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Evan Gay <Evan.Gay@ergon.com>
To: "Tipane, Frederick" <frederick.tipane@wv.gov>

Mon, Aug 18, 2025 at 12:00 PM

Thanks so much, Fred.

Evan

From: Tipane, Frederick <frederick.tipane@wv.gov>
Sent: Monday, August 18, 2025 10:04 AM
To: Evan Gay <Evan.Gay@ergon.com>
Cc: Greir Merchant <Greir.Merchant@ergon.com>; Caleb Gingerich <caleb.gingerich@trinityconsultants.com>; George Mesing <gmesing@trinityconsultants.com>; Dan Shaw <Dan.Shaw@ergon.com>
Subject: Re: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

Good morning Evan,

I will start reviewing your comments and will get back to you hopefully before the end of this week.

Fred

On Mon, Aug 18, 2025 at 10:15 AM Evan Gay <Evan.Gay@ergon.com> wrote:

Good morning, Fred –

Please find our comments attached. Let me know if you have any questions at all.

As always, we appreciate your work on this.

Evan

Evan Gay**Sr Environmental Engineer****Corporate Environmental – Projects Team****Ergon, Inc.**

M 601-337-1591

P 601-933-3097



From: Tipane, Frederick <frederick.tipane@wv.gov>

Sent: Wednesday, July 30, 2025 2:35 PM

To: Evan Gay <Evan.Gay@ergon.com>; Greir Merchant <Greir.Merchant@ergon.com>

Subject: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

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Please feel free to contact me with any questions or concerns or if you wish to discuss any issues..

Regards,

Fred

--



Frederick Tipane

Division of Air Quality

[601 57th Street, SE](#)

[Charleston, WV 25304](#)

(304) 414-1910

frederick.tipane@wv.gov

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Tipane, Frederick <frederick.tipane@wv.gov>

RE: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Evan Gay <Evan.Gay@ergon.com>

Mon, Aug 18, 2025 at 10:15 AM

To: "Tipane, Frederick" <frederick.tipane@wv.gov>

Cc: Greir Merchant <Greir.Merchant@ergon.com>, Caleb Gingerich <caleb.gingerich@trinityconsultants.com>, George Mesing <gmesing@trinityconsultants.com>, Dan Shaw <Dan.Shaw@ergon.com>

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Evan

Evan Gay

Sr Environmental Engineer

Corporate Environmental – Projects Team

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Regards,

Fred

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Frederick Tipane

Division of Air Quality

601 57th Street, SE

Charleston, WV 25304

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frederick.tipane@wv.gov

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Pre-DPPermit03 R30-02900008-2021(SM01 MM03) - Trinity Comments v2.0.docx
9685K

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:

Ergon – West Virginia, Inc.

[Newell Refinery](#)

R30-02900008-2021

Laura M. Crowder

Director, Division of Air Quality

Issued: February 9, 2021 • Effective: February 23, 2021
Expiration: February 9, 2026 • Renewal Application Due: August 9, 2025

Permit Number: **R30-02900008-2021**
Permittee: **Ergon – West Virginia, Inc.**
[Facility Name: Newell Refinery](#)
Permittee Mailing Address: **[9995 Ohio River Blvd.](#), ~~P. O. Box~~ 356, Newell, WV 26050**

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:	9995 Ohio River Blvd., Newell, Hancock County, West Virginia
Telephone Number:	304-387-4343
Type of Business Entity:	Corporation
Facility Description:	Petroleum Refinery
SIC Codes:	2911
UTM Coordinates:	531.25 km Easting • 4495.35 km Northing • Zone 17

Permit Writer: Robert Mullins

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.

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

1.1. Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
CDU	CDU	Crude Distillation Unit	1972/2012/2015	9,617,750 bbls/yr	00A-01
001-01	H-101R	CDU Atmospheric Heater; refinery fuel gas/natural gas blend	2012	54.5 MMBtu/hr	N/A
001-02	H-102R	CDU Vacuum Heater; refinery fuel gas/natural gas blend	2012	39.2 MMBtu/hr	N/A
002-01	H-201	PDR Heater; refinery fuel gas/natural gas blend	1972	6.6 MMBtu/hr	N/A
003-01	MEK-TOL	Solvent Dewaxing Unit	1972	N/A	N/A
004-01	H-500S	H500 Series Heaters (5 heaters to common stack) Unifiner/Platformer Unit; refinery fuel gas/natural gas blend	1972/2013/2016 ~~2015~~	59.6 MMBtu/hr	N/A
004-02	H-501R	Unifiner Charge Heater	2013	11.5 MMBtu/hr	N/A
005-01	H-600S	H600 Series Heaters, (4 heaters to common stack) ISOMAX Unit; refinery fuel gas/natural gas blend	1972	41.6 MMBtu/hr	N/A
005-02	H-441	Hydrogen Plant Heater; natural gas	1972	12.3 MMBtu/hr	N/A
006-01	H-701	VFU Heater; refinery fuel gas/natural gas blend	1983	12.1 MMBtu/hr	N/A
EPN 01	H-901	DHT Heater	2005	27.5 MMBtu/hr	n/a
EPN 03	H-1101	Hydrogen Plant Heater	2005	38.8 MMBtu/hr	n/a
007-01	Boiler A	Boiler A; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	N/A
007-02	Boiler B	Boiler B; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	N/A
007-03	Boiler C	Boiler C; refinery fuel gas/natural gas blend	2000	95 MMBtu/hr	N/A
TDB01	TDB01	Solar Titan 130-23001S Natural Gas Fired Combustion Turbine (CT) with generator coupled with heat recovery steam generator (HRSG)	2025	15 MW (gross output)	n/a
		Refinery fuel gas/natural gas blend fired duct burner		77.6 MMBtu/hr	n/a
CCT01	CCT01	COGEN Fluid Cooler (closed circuit cooling unit)	2025	2,016 GPM	n/a
Portable Boiler	Portable Boiler	Portable Boiler; Natural Gas	2020	99.9 MMBtu/hr Max	N/A
009-01	T Load	Truck Loading	1972/2012/2013	397.8 MMgal/yr	00A-02*

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Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
Rail-UL	Rail-UL	Rail Car Unloading	2019	800 gpm	N/A
009-02	MLD	Marine Barge Loading	1972/2012	460.7 MMgal/yr	00A-04**
00A-01	F1	Main Flare	1972	N/A	N/A
00A-03	F2	Sour Gas Flare	1972	N/A	N/A
00A-02	OXIDIZER	Thermal Oxidizer - 98.7% Min Efficiency	1994/2012 /2013	17,346 MMBtu/yr	N/A
00A-04	MLDOX	Barge Loading Thermal Oxidizer - 98% Min Eff	2012	59.0 MMBtu/hr	N/A
00B-01	WWT	Wastewater Treatment Plant	1972/1997	600 gpm	00A-03
00B-02	EQLEAKS	Equipment Leak Fugitives	N/A	N/A	N/A
00D-01	Dehy Htr	Dehydration Heater	1991	0.59 MMBtu/hr	N/A
00D-02	Still	Glycol Dehydration Still	1991	N/A	N/A
~~EPN-01~~	~~H-901~~	~~DHT Heater~~	~~2005~~	~~27.5 MMBtu/hr~~	~~N/A~~
~~EPN-03~~	~~H-1101~~	~~Hydrogen Plant Heater~~	~~2005~~	~~38.8 MMBtu/hr~~	~~N/A~~
FWPUMP1	FWPUMP1	Diesel Firewater Pump at River Dock	2005	210 hp	N/A
FWPUMP2	FWPUMP2	Diesel Firewater Pump at Boiler House	1993	265 hp	N/A
CEG01	CEG01	COGEN Black-Start Deisel Emergency Generator (Generac Model S12R-Y2PTAQ-1; Model Yr. 2023 or later)	2025	1,881 HP	N/A
Tanks					
4000	TK-4000	External floating roof; crude oil; mechanical shoe	1992/2012	2,310,000 gallons	N/A
4001	TK-4001	External floating roof; crude oil; mechanical shoe	1973/2012	2,310,000 gallons	N/A
4002	TK-4002	External floating roof; heavy products or kerosene; mechanical shoe	1970	2,310,000 gallons	N/A
4003	TK-4003	External floating roof; heavy products or kerosene; mechanical shoe	1970	2,310,000 gallons	N/A
4004	TK-4004	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4005	TK-4005	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4006	TK-4006	External floating roof; gasoline; mechanical shoe	1971/2018	1,260,000 gallons	N/A
4007	TK-4007	Fixed roof; heavy products	1971	2,310,000 gallons	N/A
4008	TK-4008	Fixed roof; heavy products	1970	1,260,000 gallons	N/A
4009	TK-4009	Fixed roof; heavy products or kerosene	1971	1,260,000 gallons	N/A
4010	TK-4010	Fixed roof; heavy products	1970	1,260,000 gallons	N/A

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Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
4011	TK-4011	Fixed roof; heavy products or kerosene	1971	1,239,568 gallons	N/A
4012	TK-4012	Internal floating roof; gasoline; vapor mounted	1971	630,000 gallons	N/A
4013	TK-4013	Internal floating roof; gasoline; vapor mounted	1971	630,000 gallons	N/A
4014	TK-4014	External floating roof; gasoline; mechanical shoe	1971/2013	315,000 gallons	N/A
4015	TK-4015	External floating roof; gasoline; mechanical shoe	1971/2013	315,000 gallons	N/A
4016	TK-4016	External floating roof; gasoline; mechanical shoe	1971	315,000 gallons	N/A
4017	TK-4017	Fixed roof; heavy products	1971	840,000 gallons	N/A
4018	TK-4018	Fixed roof; heavy products	1971/2000	704,970 gallons	N/A
4019	TK-4019	Fixed roof; heavy products	1971	704,970 gallons	N/A
4020	TK-4020	Fixed roof; heavy products	1971	840,000 gallons	N/A
4021	TK-4021	Fixed roof; heavy products	1971	840,000 gallons	N/A
4022	TK-4022	Fixed roof; heavy products	1971	571,200 gallons	N/A
4023	TK-4023	Fixed roof; heavy products	1971	571,200 gallons	N/A
4024	TK-4024	Fixed roof; heavy products	1970	840,000 gallons	N/A
4025	TK-4025	Fixed roof; heavy products	1970	840,000 gallons	N/A
4026	TK-4026	Fixed roof; heavy products	1970	840,000 gallons	N/A
4027	TK-4027	Fixed roof; heavy products	1971	840,000 gallons	N/A
4028	TK-4028	Fixed roof; heavy products	1970	210,000 gallons	N/A
4029	TK-4029	Fixed roof; heavy products	1971	65,100 gallons	N/A
4030	TK-4030	Fixed roof; heavy products	1971	65,100 gallons	N/A
4031	TK-4031	Fixed roof; heavy products	1971	315,000 gallons	N/A
4032	TK-4032	Fixed roof; heavy products	1971	315,000 gallons	N/A
4033	TK-4033	Fixed roof; heavy products	1970	315,000 gallons	N/A
4034	TK-4034	Fixed roof; heavy products	1998	840,000 gallons	N/A
4035	TK-4035	Fixed roof; heavy products	1983	840,000 gallons	N/A
4036	TK-4036	Fixed roof; heavy products	1973	315,000 gallons	N/A
4037	TK-4037	Fixed roof; heavy products	1973	315,000 gallons	N/A
4038	TK-4038	Fixed roof; heavy products	1976	840,000 gallons	N/A
4039	TK-4039	Fixed roof; heavy products	1977	1,260,000 gallons	N/A
4040	TK-4040	Fixed roof; heavy products	1978	630,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
4041	TK-4041	Fixed roof; heavy products	1973	630,000 gallons	N/A
4042	TK-4042	Fixed roof; heavy products	1978	630,000 gallons	N/A
4043	TK-4043	Fixed roof; heavy products	1978	630,000 gallons	N/A
4044	TK-4044	Fixed roof; heavy products	1982	1,260,000 gallons	N/A
4045	TK-4045	Fixed roof; heavy products	1982	630,000 gallons	N/A
4046	TK-4046	Fixed roof; heavy products	1982	630,000 gallons	N/A
4047	TK-4047	Fixed roof; heavy products, MTVP <3.5kPa	1986	1,260,000 gallons	N/A
4048	TK-4048	Fixed roof; heavy products	1986	504,000 gallons	N/A
4050	TK-4050	Internal floating roof; gasoline; mechanical shoe	1993/2013	630,000 gallons	N/A
4051	TK-4051	Fixed roof; heavy products, MTVP <3.5kPa	1996	1,260,000 gallons	N/A
4052	TK-4052	Fixed roof; ethanol	1972	30,240 gallons	N/A
4053	TK-4053	Fixed roof; ethanol	1972	30,240 gallons	N/A
4054	TK-4054	Fixed roof; heavy products or kerosene	1998	625,000 gallons	N/A
4055	TK-4055	Fixed roof; heavy products or kerosene	1998	625,000 gallons	N/A
4056	TK-4056	Fixed roof; heavy products or kerosene	1999	625,000 gallons	N/A
4057	TK-4057	Fixed roof; heavy products or kerosene	1999	625,000 gallons	N/A
4060	TK-4060	Internal floating roof; crude; mechanical shoe	1999/2012 /2015	5,040,000 gallons	N/A
4061	TK-4061	Internal floating roof; crude; mechanical shoe	2008/2012 /2015	5,040,000 gallons	N/A
4062	TK-4062	Internal floating roof; light crude oil with vapor pressure < 11.0 psia; mechanical shoe	2008/2012	5,040,000 gallons	N/A
4063	TK-4063	Internal floating roof; light crude oil with vapor pressure < 11.0 psia; mechanical shoe	2012	5,040,000 gallons	N/A
4066	TK-4066	Fixed roof; Biodiesel Tank	2011	40,000 gallons	N/A
4069	TK-4069	Fixed roof; Biodiesel Tank	2017	126,000 gallons	N/A
4070	TK-4070	Internal floating roof; ethanol; mechanical shoe	2018	630,000 gallons	N/A
4071	TK-4071	External floating roof; gasoline; mechanical shoe	2018	1,260,000 gallons	N/A
4072	TK-4072	Fixed roof; feedstock	2018	1,260,000 gallons	N/A
4073	TK-4073	Fixed roof; heavy products	2020	32,800 barrels	N/A
4103	TK-4103	Fixed roof; heavy products	1970	127,000 gallons	N/A
4104	TK-4104	Fixed roof; heavy products	1970	127,000 gallons	N/A

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed/Modified	Design Capacity	Control Device
V-4002	V-4002	NGL Bullet Tank	2016	10,984 ft ³	fuel gas system
V-4003	V-4003	NGL Bullet Tank	2016	10,984 ft ³	fuel gas system
00A-03	CARBONBED	Carbon Bed Adsorber	2002	6,000 cfm	N/A
Process Vessels					
303	TK-303	Fixed roof; MEK	1970	7,875 gallons	N/A
304	TK-304	Fixed roof; Toluene	1970	7,875 gallons	N/A
NS-FUG	NS-FUG	Naphtha Splitter Fugitives	2011	N/A	N/A
ISOM	ISOM	Processing Unit: Benzene Reduction	2012	21.6 MMgals/yr	N/A
ADU	NH3OX	Ammonia Destruction Unit	2015	N/A	00A-05
00A-05	NH3OX	Ammonia Destruction Unit Thermal Oxidizer - 99.9% DRE	2015	6.6 MMBtu/hr	N/A
ADUFUG	ADUFUG	Ammonia Destruction Unit Fugitives	2015	N/A	N/A
PL-FUG	PL-FUG	Platformer Expansion Fugitives	2015	N/A	N/A
YNGL-FUG	YNGL-FUG	Y-Grade NGL Fugitives	2015	N/A	N/A

* Control Device for Gasoline Loading Only

** Control Device for Gasoline and Light Crude Oil Loading Only

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- ~~2334AK~~ A1	~~August 22, 2025~~ September-23, 2021

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 ~~such~~ 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~~, ~~2.12~~). 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	PM₁₀	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	SO₂	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		
mmft³/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 39]

2.12. Reasonably Anticipated Operating Scenarios

- 2.12.1. The following are terms and conditions for reasonably anticipated operating scenarios identified in this permit.
- 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.
 - The permit shield shall extend to all terms and conditions under each such operating scenario; and
 - 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:
- 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;
 - Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
 - 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;
 - 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:
- 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
 - 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~~ Emergency

- ~~2.17.1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.~~
- ~~[45CSR§30-5.7.a.]~~

- ~~2.17.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of 45CSR§30-5.7.e. are met.~~
- ~~[45CSR§30-5.7.b.]~~

- ~~2.17.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:~~
- ~~An emergency occurred and that the permittee can identify the cause(s) of the emergency;~~
 - ~~The permitted facility was at the time being properly operated;~~
 - ~~During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and~~

~~d.— Subject to the requirements of 45CSR§30-5.1.e.3.C.1, the permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice, report, and variance request fulfills the requirement of 45CSR§30-5.1.e.3.B.—This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.~~

~~[45CSR§30-5.7.e.]~~

~~2.17.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.~~

~~[45CSR§30-5.7.d.]~~

~~2.17.5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.~~

~~[45CSR§30-5.7.e.]~~

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. and ~~45CSR38~~

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 14)]
- 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:
- 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.
 - 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.** This stationary source, as defined in 40 CFR § 68.3, is subject to Part 68. This stationary source has submitted a risk management plan (RMP) by the date specified in 40 CFR §68.10. This stationary source shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 CFR Part 70 or 71.

[40 CFR 68]

- 3.1.9. **Sulfur Dioxide.** The Company agrees that it shall not operate any source of sulfur dioxide emissions unless such source is in compliance with the Code, terms of CO-SIP-95-1, and any additional or more stringent provisions of 45CSR10 - "To Prevent and Control Air Pollution From the Emissions of Sulfur Oxides".

[CO-SIP-95-1 - IV.1. (SIPed)]

- 3.1.10. **Sulfur Dioxide.** The Company agrees that at all times, including periods of source start-up, shut down, and malfunction, that it will, to the extent practicable, maintain and operate all sources of sulfur dioxide emissions, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.

[CO-SIP-95-1 - IV.2. (SIPed)]

- 3.1.11. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, operate, and maintain 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.

[45CSR13: Permit R13-2334, 4.1.20, 4.1.5, 45CSR§13-5.10, 11.]

- 3.1.12. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R13-2334 through R13-2334AK AIF and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to.

[45CSR13: Permit R13-2334, 2.5.1.]

- 3.1.13. Facility wide emissions of all combined HAPs (including combustion related HAPs) shall not exceed 24.99 tons per year. Facility wide emissions of any individual HAP (including combustion related HAPs) shall not exceed 9.99 tons per year. Compliance with this condition shall be determined using a rolling 12 month total.

[45CSR13: Permit R13-2334, 12.1.1]

3.2. Monitoring Requirements

- 3.2.1. In order to determine compliance with this condition, the applicant shall calculate facility wide emissions of HAPs on a monthly basis. Said emission calculations shall be based on one of the following:
 - a. Continuous Emissions Monitoring
 - b. Predictive Emissions Monitoring

- c. USEPA approved source testing
- d. Material balance
- e. AP-42
- f. Manufacturer's Data

[45CSR13: Permit R13-2334, 12.2.1]

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 in 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)(~~14-15-16~~) 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.; R13-2334, 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.]

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 Maintenance of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures. [45CSR13: Permit R13-2334, Condition 4.4.2.]

3.4.5. **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: Permit R13-2334, Condition 4.4.3.]

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](#) ~~Section~~ (3ED21)
[Four Penn Center](#)
[1600 John F. Kennedy Boulevard](#) ~~1650 Arch Street~~
Philadelphia, PA 19103-~~2852~~ 2029

DAQ Compliance and Enforcement¹:

DEPAirQualityReports@wv.gov

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

- 3.5.4. ~~**Fees, Certified emissions statement.**~~ The permittee shall ~~submit a certified emissions statement and~~ pay fees on an annual basis in accordance with [45CSR§30-8](#). ~~the submittal requirements of the Division of Air Quality.~~
[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:

DEPAirQualityReports@wv.gov

US EPA:

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. Emergencies.**~~ ~~For reporting emergency situations, refer to Section 2.17 of this permit.~~

- 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. Any deviation resulting from an emergency or upset condition, as defined in 45CSR§30-5.7., shall be reported by telephone or telefax within one (1) working day of the date on which the permittee becomes aware of the deviation, if the permittee desires to assert the affirmative defense in accordance with 45CSR§30-5.7. A written report of such deviation, which shall include the probable cause of such deviations, and any corrective actions or preventative measures taken, shall be submitted and certified by a responsible official within ten (10) days of the deviation.~~
 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~~ telefax. 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. EWVI has certified that it has completed its obligations from the Consent Judgment (97-C-338), therefore the requirements from the Consent Judgment are no longer included in the Title V Permit.

- b. 40 CFR Part 60, Subpart D - The boilers at the Newell Refinery do not have rated capacities greater than 250 MMBTU/hr.
- c. 40 CFR Part 60, Subpart Da - The boilers at the Newell Refinery are not in electric utility service and do not have rated capacities greater than 250 MMBTU/hr.
- d. 40 CFR Part 60, Subpart Db - The Newell Refinery does not have steam generating units that commenced construction, modification or reconstruction after June 19, 1984 with a rated capacity greater than 100 MMBTU/hr.
- e. 40 CFR Part 60 Subpart Dc - National Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units does not apply to process heaters H-101R, H-102R, and H-501R because although they have maximum design heat inputs between 10 and 100 MMBtu/hr, they do not meet the definition of a “steam generating unit.” The Portable Boiler is also not subject to this subpart since it is defined as a temporary boiler and per 40 C.F.R. §60.40c(i), “temporary boilers” are not subject to the subpart.
- f. 40 CFR Part 60 Subpart RRR - National Standards of Performance for Volatile Organic Compounds (VOC) Emissions from Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Reactor Processes does not apply to EWVI since it does not produce any of the chemicals listed in 40 CFR §60.707 as a product, co-product, by-product, or intermediate.
- g. 40 CFR Part 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene. The provisions of this subpart apply to each of the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges, and other connectors, product accumulator vessels, and control devices or systems required by this subpart. To be covered by this Subpart, the equipment must be in benzene service. In benzene service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The Newell Refinery does not have any equipment that is in benzene service.
- h. 40 CFR Part 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources). The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air pollutant service: pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges, and other connectors, product accumulator vessels, and control devices or systems required by this subpart.

The provisions of this subpart apply after the promulgation of a specific subpart in Part 61. For example, If the refinery was subject to 40 CFR Part 61, Subpart J (which it is not), then the refinery would have to comply with the equipment leak provisions of 40 CFR Part 61, Subpart V. The actual equipment leak standards are contained in Subpart V. If one is subject to Subpart J, then Subpart J refers one to Subpart V for the actual compliance standards. In summary, the Newell Refinery would have to be subject to some other subpart in Part 61 that referred to Subpart V before Subpart V would be applicable.

- i. 40 CFR Part 63 - EWVI has demonstrated that the facility is not a major source of HAPs and never has been. MEK is a major constituent of the EWVI HAP emissions and has now been delisted. [70 Fed. Reg. 75047 (December 19, 2005)] Further, EPA has made the determination that the delisting of MEK may be applied retroactively. Therefore, the “once in, always in” policy would not apply. In addition,

more accurate emissions calculation methodologies have been developed for estimating fugitive emissions. Applying the more accurate emissions methodologies demonstrates that emissions from the MEK-TOL unit never exceeded the major threshold, even when combined with other sources of HAP emissions at the refinery. Retroactively applying the more accurate calculation methods for determining fugitive emissions from the MEK-TOL unit, added to the rest of the facility's HAP emissions, determined that facility-wide HAP PTEs have always been less than 10 tons per year of a single HAP and 25 tons per year of aggregate HAPs. Therefore, 40 CFR Part 63, Subparts H, R, Y, CC, OO, PP, QQ, RR, VV, UUU, EEEE, [YYYY](#), GGGGG, and DDDDD do not apply to this source.

- j. 40 CFR Part 63 Subpart JJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers, which is an area source MACT rule, does not apply to EWVI's boilers and process heaters per 40 CFR §63.11195 (e), since they are gas fired.

4.0 Fuel Burning Units Requirements [Boilers A, B, & C, Portable Boiler, [Process](#) Heaters H-101R, H-102R, H-201, H-500S, H-501R, H-600S, H-441, H-701, H-901, and H-1101; [Combustion Turbine w/Duct Burner](#)]

Emission Unit	Applicable Rule	Limits Section 4.1:	Monitoring Section 4.2:	Testing Section 4.3:	Recordkeeping Section 4.4:	Reporting Section 4.5
Boilers A&B	45CSR2	1, 2, 3, 4, 7, 8, 9	3		2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5, 8	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 14, 25	1, 3, 8, 9, 13		1, 2, 3, 4, 5, 6, 8	1, 2
	CO-SIP-95	15, 16	2, 4, 5, 6, 7, 9	2, 3	7, 8	3, 4
Boiler C	40CFR60	9, 12, 25	9		6	
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13, 17	8		4, 5	
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 17, 25	1, 8, 9, 10, 11		1, 2, 3, 4, 5, 9	1, 5, 6
	CO-SIP-95		9	3		
	40CFR60	9, 12, 25	9			5
Portable Boiler	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 28, 29, 30, 31, 32	1, 15		2, 3, 19, 20	1
H-101R & H-102R	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5	2
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 18, 26, 27	1, 8, 14	1	1, 2, 3, 4, 5, 12, 18	1, 2, 8, 9
	40CFR60	9, 18, 26, 27	14	1	16	8, 9
H-201	45CSR2	1, 2, 3, 4				
	45CSR10	5			14	
	45CSR13	1, 3, 4, 6, 12, 19, 25	1, 9		1, 6, 14	
	CO-SIP-95		2, 9, 10	2, 3	7, 14	3, 4
	40CFR60	12, 25	9		6	
H-441	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 19				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 10, 11, 19, 20	1		1, 2, 3, 13	1
	CO-SIP-95	20	2, 7			3, 4
	40CFR60	9				
H-701	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13, 19	8		4, 5, 14	
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 19, 25	1, 8, 9		1, 2, 3, 4, 5, 6, 14	1
	CO-SIP-95	21	2, 7, 9	2, 3	7, 14	3, 4
	40CFR60	9, 12, 25	9		6	
H-500S & H-600S	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5, 14	2
	CO-SIP-95		2, 7, 9, 10	2, 3	7, 14	3, 4
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 22, 25	1, 8		1, 2, 3, 4, 5, 14	1, 2
	500S only	26	14	1	18	8, 9
	600S only	12	9		6	
	40CFR60	9, 25		1		8, 9
	500S only	26	14		18	

Emission Unit	Applicable Rule	Limits Section 4.1.	Monitoring Section 4.2.	Testing Section 4.3.	Recordkeeping Section 4.4.	Reporting Section 4.5
	600S only	12	9		6	
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8		4, 5	2
H-501R	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 13, 18, 26, 27	1, 8, 14	1	1, 2, 3, 4, 5, 12, 18	1, 2, 8, 9
	40CFR60	9, 18, 26, 27	14	1	18	8, 9
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
	45CSR10	5, 10, 11, 13	8			2
H-901	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 12, 13, 23, 25	1, 8, 9, 11		1, 2, 3, 6, 15, 16	1, 2, 7
	CO-SIP-95		9	3	7	
	40CFR60	9, 12, 25	9		6	7
	45CSR2	1, 2, 3, 4, 7, 8, 9			2, 3	1
H-1101	45CSR10	5, 10, 11				
	45CSR13	1, 3, 4, 6, 7, 8, 9, 11, 23, 24	1, 12		1, 2, 3, 17	1

4.1. Limitations and Standards

All boilers and heaters

4.1.1. Boilers A and B are “fuel gas combustion device” under Subpart J of 40 CFR 60. Boilers A and B are “fuel burning units” under 45CSR2 and 45CSR10; and “combusting refinery gas stream” in Section 5 of 45CSR10. The following conditions and requirements are specific to boilers identified as Boiler A and Boiler B: 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.

a. The emissions released from each Emission Points “Boiler A” and “Boiler B” shall not exceed following individual emission rates.

CO & VOC limits for Boilers A and B		
Pollutant	Emission Rate	
	TPM	TPY
CO	5.76	57.54
VOC	0.383.77	3.79

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NO_x emissions from the respective emission point of each boiler shall not exceed 0.058 lb/MMBtu on a three (3) hour rolling average basis.
- c. PM emissions from the respective emission points of each boiler shall not exceed 1.44 pounds per hour on a 6-hour average basis. Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.
- d. Each boiler shall not exhibit visible emissions from respective emission points greater than 10% opacity on a six (6) minute average basis.

Commented [CG3]: Current permit limit is 0.75 tpm.

Commented [GM4R3]: There is a slipped decimal on the 3.77; as it should be 0.377 or 0.38 (for single unit; old 0.75 tpm is for 2 units).

- e. ~~Each boiler shall be fired with refinery fuel gas (RFG) that meets the requirements in Conditions 4.1.16 and 4.1.17.~~
- e. ~~Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limits in 45CSR§10-3.1.5 and CO-SIP-95-1 – Condition IV.3.B.b.~~
- f. ~~Any modifications or replacement of the stacks from Boilers No. A and B shall comply with the provisions of 45CSR20 "Good Engineering Practice as Applicable to Stack Heights".~~

~~[45CSR§2-3.1.; 45CSR2-4.1.2.; 45CSR§10-3.1.5.; CO-SIP-95-1 - Conditions IV.3.B.b. and IV.10. (SIPed); and 45CSR13: Permit R13-2334, 4.1.1.]~~

- 4.1.2. 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 Director. 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 Director.

~~[45CSR§2-4.4.]~~

- 4.1.3. ~~Boiler C is a "fuel gas combustion device" under Subpart Ja; "fuel burning unit" under 45CSR2 and 45CSR10; and "combusting refinery gas stream" in Section 5 of 45CSR10. The following conditions and requirements are specific to the boiler identified as Boiler C: In the event of an unavoidable shortage of fuel having characteristics or specifications necessary for a fuel burning unit to comply with the visible emission standards set forth in 45CSR§2-3.1. or any emergency situation or condition creating a threat to public safety or welfare, the Director may grant an exception to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during the exception period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the emission standards under 45CSR§2-4.1.b. will not be exceeded during the exemption period.~~

~~[45CSR§2-10.1. and 45CSR13: Permit R13-2334, 4.1.2.]~~

- a. ~~The emissions released from Emission Points "Boiler C" shall not exceed following individual emission rates.~~

Emission Limits for Boiler C		
Pollutant	Emission Rate	
	TPM	TPY
CO	3.43	34.27
VOC	0.22	2.24

~~TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.~~

- b. ~~NO_x emissions from Emission Point "Boiler C" shall not exceed 0.050 lb/MMBtu on a three-hour average basis. Boiler C shall be equipped with low NO_x burners.~~
- c. ~~PM emissions from Emission Point "Boiler C" shall not exceed 0.86 pounds per hour on a 6-hour average basis. Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.~~
- d. ~~Boiler C shall not exhibit visible emissions from Emission Point "Boiler C" greater than 10% on a six (6) -minute average basis.~~

Commented [CG5]: General comment: putting all the citations at the end of the sections makes it difficult to understand the underlying requirement for the individual conditions, which have different basis. It also makes it nearly impossible to QA these citations. Recommend placing each applicable underlying requirement after each sub-condition. Recommend updating as part of the renewal.

- e. ~~The boiler shall either combust natural gas or “fuel gas” that meets the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.~~

~~[45CSR§2-3.1.; 45CSR2-4.1.2.; 45CSR§10-3.1.5.; 45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); and 45CSR13: Permit R13-2334, 4.1.2.]~~

- 4.1.4. ~~The following conditions and requirements are specific to Combustion Turbine #1 with duct burner, which is referred to as TBD01; The TBD01 duct burner is a “fuel gas combustion device” under Subpart Ja; TBD01 is a “fuel burning unit” under 45CSR2 and 45CSR10; In the event a fuel burning unit employing a flue gas desulfurization system must by-pass such system because of necessary planned or unplanned maintenance, visible emissions may not exceed twenty percent (20%) opacity during such period of maintenance. The Director may require advance notice of necessary planned maintenance, including a description of the necessity of the maintenance activity and its expected duration and may limit the duration of the variance or the amount of the excess opacity exception herein allowed. The Director shall be notified of unplanned maintenance and may limit the duration of the variance or the amount of excess opacity exception allowed during unplanned maintenance.~~
~~[45CSR§2-10.2. and 45CSR13: Permit R13-2334, 4.1.3.]~~

- a. ~~Emissions from TBD01 shall not exceed the following:~~

- i. ~~TBD01 shall not discharge nitrogen oxides (NO_x) emissions in excess of 1.2 lb of NO_x per MWh on a 30-day rolling average basis.~~
- ii. ~~TBD01 shall not discharge sulfur dioxide (SO₂) emissions in excess of 0.90 lb of SO₂/MWh on a gross output basis or 0.060 lb of SO₂/MMBtu on a heat input basis.~~

~~Compliance with the heat input standard limit shall be satisfied with either current, valid purchase contract, tariff sheet or transportation contract for the natural gas specifying that the maximum total sulfur content for the natural gas is no greater than 20 grains per 100 cubic feet of gas, consuming a gaseous fuel (refinery fuel gas) that does not exceed 0.060 lb SO₂/MMBtu heat input based fuel monitoring outline in Condition 4.2.9., or combination of these methods for each type of fuel consumed by the turbine.~~

- b. ~~Mass hourly emissions from Emission Point TDB01 shall not exceed the following limits regardless of the operation of the duct burner:~~

Emission Limit for Emission Point TDB01		
Pollutant	Emission Rate	
	Hourly Limit (lb/hr)	Annual Limit (TPY)
CO	12.55	56.35
PM ₁₀ /PM _{2.5}	1.81	7.92
VOC	1.50	6.96
Formaldehyde	0.13	0.56
Total HAPs	0.32	1.38

Only the hourly CO and VOC limits in the above table do not apply during startup and shutdown events.

- c. At all times when the duct burner is firing, visible emissions from Emission Point TDB01 shall not be greater than ten (10) percent opacity based on a six-minute average.
- d. At all times when the duct burner is firing, PM emissions from Emission Point TDB01 shall not exceed 1.23 pounds per hour on a 6-hour average basis. *Compliance with this streamlined PM limit ensures compliance with 45CSR§2-4.1.2.*
- e. Annual mass NO_x emissions from Emission Point TDB01 shall not exceed 39.95 tons per year on a 12-month rolling total basis. This limit shall include NO_x emissions due to the startup events, shutdown events, operating in SoLoNO_xTM mode, operation in non-SoLoNO_xTM mode from the combustion turbine, and NO_x emissions from the duct burner. Any future relaxation of this limit shall only be authorized in accordance with 45CSR14.
- f. The permittee must operate and maintain the 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.

The permittee shall operate TBD01 at a load condition that allows the for the operation of the SoLoNO_xTM mode with the Enhanced Emission Control Systems to be engaged at all times except during startup and shutdown events and when ambient air temperatures are below 0 F. The permittee must minimize the time spent during startup and shutdown events which shall not exceed 180 minutes per startup event. Ending/completion of the startup event shall be defined once the CT has reached the 50% load. Once the combustion turbine has successfully started up, the permittee shall in a timely manner increase the loading on the combustion turbine to engage the SoLoNO_xTM mode with the Enhanced Emission Control Systems to minimize emissions. Operating the combustion turbine at idle conditions is not permitted except when transitioning from a successful startup event to a load condition that the SoLoNO_xTM mode can be engaged or when transiting from normal operations with SoLoNO_xTM mode operating to a shutdown event. Monitoring the status of the SoLoNO_xTM operating mode shall be conducted using the parameters with associated operating ranges for the system stated by the turbine manufacture's latest written specifications (e.g., PIL 220).

- g. The duct burner is limited to consuming "fuel gas" meeting the specifications stated in Conditions 4.1.15, and 4.1.17. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*
- h. The maximum amount of energy inputted into the combustion turbine shall not exceed 172 MMBtu/hr on a 24-hour average basis.
- i. The maximum amount of energy input from the duct burner shall not exceed 77.6 MMBtu/hr on a 24-hour average basis.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§§10-3.1.5. & 3.8.; 45CSR§10-5.1.; 45CSR16; 40 CFR §60.102(a)(1)(ii); 40 CFR §60.4320(a), Table 1 to 40 CFR 60 Subpart KKKK, §§60.4330(a)(1) & (a)(2), §60.4333(a), §60.4365(a), §60.4415(a)(1); and 45CSR13: Permit R13-2334, 4.1.4.]

- 4.1.5. Heater H-101R is a "fuel gas combustion device" under Subpart Ja of 40 CFR 60; and "process heater" under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to

Heater H-101R for the crude distillation unit: ~~Due to unavoidable malfunction of equipment or inadvertent fuel shortages, emissions exceeding those provided for in 45CSR10 may be permitted by the Director for periods not to exceed ten (10) days upon specific application to the Director. Such application shall be made within twenty-four (24) hours of the equipment malfunction or fuel shortage. In cases of major equipment failure or extended shortages of conforming fuels, additional time periods may be granted by the Director provided a corrective program has been submitted by the owner or operator and approved by the Director. [45CSR§10-9.1.]~~

- a. Emissions from Emission Point H-101R shall not exceed the following limits:

Emission Limits for Heater H-101R		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.72	7.16
PM ₁₀	0.50	1.78
PM _{2.5}	0.50	1.78
VOC	0.12	1.19

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. NO_x emissions from the heater shall not exceed 40 ppmv (dry basis, corrected to 0-percent excess air) 30-day rolling average basis. The permittee shall demonstrate compliance with this emission standard by operating this heater in a manner that the daily average O₂ in the heater's exhaust does not exceed the O₂ operating limit or O₂ operating curve determined during the most recent biennial performance test as required in Condition 4.3.1. of this permit.
- c. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii), §60.102a(g)(2)(i)(A), §60.107a(i)(5); and 45CSR13: Permit R13-2334, 4.1.5.]

- 4.1.6. Heater H-102R is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-102R ~~for the crude distillation unit. The facility shall not burn Fuel Oil in any combustion unit, except during periods of natural gas curtailment and/or during periods of DOT required maintenance of the natural gas pipeline in which the facility shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur). Note: Fuel Oil is defined as any liquid fossil fuel with sulfur content greater than 0.05% by weight.~~

~~[45CSR13: Permit R13-2334, 4.1.4.]~~

- a. Emissions from Emission Point H-102R shall not exceed the following limits

Emission Limits for Heater H-102R		
Pollutant	Emission Limits	
	TPM	TPY

Commented [CG6]: Two options are available in NSPS Ja for compliance. Note that other sections of the permit correctly identify the two options. Recommend updating to align with other sections of the permit.

Commented [CG7]: Recommend removing process unit name, which can be referenced from Table 1.

Emission Limits for Heater H-102R		
CO	0.51	5.15
NO _x	1.12	11.16
PM ₁₀	0.36	1.28
PM _{2.5}	0.36	1.28
VOC	0.12	0.86

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii);45CSR13: Permit R13-2334, 4.1.6.]

All Boilers and Heaters Except H-201

- 4.1.7. Heater H-201 is a “fuel gas combustion device” under Subpart J of 40 CFR 60; and “process heater” under Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-201 for the crude distillation unit: ~~No person shall cause, suffer, allow or permit the discharge of particulate matter into the open air in excess of the following:~~

Emission Unit	PM Emission Limit (lbs/hr)
Boiler A	14.36
Boiler B	14.36
Boiler C	8.55
Portable Boiler	8.99
H-101R	4.91
H-102R	3.53
H-500S	5.36
H-501R	1.04
H-600S	3.74
H-441	1.11
H-701	1.09
H-901	2.48
H-1101	3.49

[45CSR§2-4.1.b. and 45CSR13: Permit R13-2334, 4.1.6.]

- a. Emissions from Emission Point H-201 shall not exceed the following limits:

Emission Limits for Heater H-201		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.43	2.38
NO _x	0.28	2.78

Commented [CG8]: Process heater is not a defined term in NSPS J. It becomes a defined term in Ja once Ja is triggered for NOx. This revision has also been proposed for other sections in the permit.

Commented [CG9]: PDR heater.

PM ₁₀	0.02	0.22
PM _{2.5}	0.02	0.22
VOC	0.02	0.16

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
 Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the fuel requirements and SO₂ lb/hr limit in 45CSR§10-3.1.5lb/mmBtu limit in CO-SIP-95-1 – Condition IV.7.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1);CO-SIP-95-1 - Condition IV.7.; 45CSR13: Permit R13-2334, 4.1.7.]

- 4.1.8. Heater H-441 is a “process heater” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-441 ~~for the crude distillation unit. The visible emission standards set forth in 45CSR§2-3 shall apply at all times except in periods of start-ups, shutdowns and malfunctions. Where the Director believes that start-ups and shutdowns are excessive in duration and/or frequency, the Director may require an owner or operator to provide a written report demonstrating that such frequent start-ups and shutdowns are necessary.~~
[45CSR§2-9.1. and 45CSR13: Permit R13-2334, 4.1.7.]

Commented [CG10]: Hydrogen plant heater.

- a. Emissions from Emission Point H-441 shall not exceed the following limits:

Emission Limits for Heater H-441		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.44	4.44
NO _x	0.53	5.28
PM ₁₀	0.04	0.40
PM _{2.5}	0.04	0.40
VOC	0.03	0.29

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
 Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. This heater shall be limited to firing exclusively on natural gas. Therefore, this heater is exempt from the requirements of subdivision 8.1.1. and subsections 8.2 of 45CSR2; and the requirements of section 8 of 45CSR10.

[46CSR§2-8.4.2.; 45CSR§10-10.3.; 45CSR13: Permit R13-2334, 4.1.8.]

- 4.1.9. Heater H-501R is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-501R ~~for the crude distillation unit. At all times, including periods of start-ups, 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 Director which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance~~

Commented [CG11]: Unifiner charge heater.

procedures and inspection of the source. Process heaters H-101R, H-102R, and H-501R shall be equipped with low-NO_x burners.

[45CSR§2-9.2., 45CSR13: Permit R13-2334, 4.1.8., 45CSR16, and 40CFR§60.11(d)]

a. Emissions from Emission Point H-501R shall not exceed the following limits:

Emission Limits for Heater H-501R		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.15	1.50
NO _x	0.33	3.27
PM ₁₀	0.04	0.38
PM _{2.5}	0.04	0.38
VOC	0.03	0.25

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii);45CSR13: Permit R13-2334, 4.1.9.]

- 4.1.10. Heaters H-502, H-503, H-504, and H-506 under H-500S are “fuel gas combustion devices” under Subpart J of 40 CFR 60; Heater H-505R under H-500S is a “fuel gas combustion device” and “process heater” under Subpart Ja of 40 CFR 60; and all the heaters under H-500S are “process heaters” under 45CSR2, and 45CSR10; The following conditions and requirements are specific to Heater H-500S for the crude distillation unit. 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 following: the product of 3.1 and the total design heat inputs for such units discharging through those stacks in million BTU's per hour. [45CSR§10-3.1.e. (Boilers A, B, and C, Portable Boiler, Heaters H-101R, H-102R, H-441, H-501R, H-500S, H-600S, H-701, H-901, and H-1101)]

a. Emissions from Emission Point H-500S shall not exceed the following limits:

Emission Limits for Heater H-500S		
Pollutant	Emission Limits	
	TPM	TPY
CO	2.02	20.16
NO _x	2.96	29.58
PM ₁₀	0.19	1.80
PM _{2.5}	0.19	1.76
VOC	0.13	1.31

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

Commented [CG12]: Unifiner/Platformer unit.

b. Heaters H-502, H-503, H-504, and H-506 shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5. Compliance with this streamlined requirement assures compliance with CO-SIP-1995-1 Sections IV.5.*

c. Heater H-505R shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); 40 CFR §60.102a(g)(1)(ii); CO-SIP-95-1 - Condition IV.5.; and 45CSR13: Permit R13-2334, 4.1.10.]

- 4.1.11. H-600S is a series of four (4) individual heaters venting to common emission point with all four-heaters classified as “fuel gas combustion devices” under Subpart J of 40 CFR 60; and “process heaters” under Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heaters under H-600S ~~for the crude distillation unit. Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on a continuous twenty-four (24) hour averaging time. The owner and/or operator of a fuel burning unit shall not allow emissions to exceed the weight emissions standards for sulfur dioxide as set forth in this rule, except during one (1) continuous twenty-four (24) hour period in each calendar month and during this one (1) continuous twenty-four hour period said owner and/or operator shall not allow emissions to exceed such weight emission standards by more than ten percent (10%) without causing a violation of this rule. A continuous twenty-four (24) hour period is defined as one (1) calendar day.~~
[45CSR§10-3.8. and 45CSR13: Permit R13-2334, 4.1.9.]

a. Emissions from Emission Point H-600S shall not exceed the following limits:

Emission Limits for Heater H-600S		
Pollutant	Emission Limits	
	TPM	TPY
CO	1.50	15.01
NO _x	2.14	21.44
PM ₁₀	0.14	1.36
PM _{2.5}	0.14	1.36
VOC	0.10	0.98

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
Annual emission limit – TPY shall be based on 12-month rolling total basis.

b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5. Compliance with this streamlined requirement assures compliance with CO-SIP-1995-1 Sections IV.5.*

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); CO-SIP-95-1, Condition IV.5.; 45CSR13: Permit R13-2334, 4.1.11.]

Commented [CG13]: ISOMAX unit.

Boilers A, B, and C, Heaters H-201, H-600S, H-701, H-901

- 4.1.12. Heater H-701 is a “fuel gas combustion device” under Subpart Ja of 40 CFR 60; and a “process heater” under Subpart Ja of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-701 for the VFU: No owner or operator shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The listed heaters and boilers are affected facilities, as that term is used in 40 CFR Part 60 Subparts A and J. [40 CFR §60.104(a)(1) and 45CSR§16 4.1; 45CSR13: Permit R13-2334, 4.1.25.]

- a. Emissions from Emission Point H-701 shall not exceed the following limits:

Emission Limits for Heater H-701		
Pollutant	Emission Limits	
	TPM	TPY
CO	0.44	4.36
NO _x	0.11	1.06
PM ₁₀	0.04	0.39
VOC	0.03	0.29

Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall be fired only with natural gas and treated refinery fuel gas. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.15, and 4.1.17. of this permit. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5. Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in CO-SIP-95-1 – Condition IV.6.

[45CSR§10-5.1.; 45CSR16; 40 CFR §60.102a(g)(1)(ii); CO-SIP-95-1 - Condition IV.6. (SIPed); 45CSR13: Permit R13-2334, 4.1.12.]

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701, H-901

- 4.1.13. Heater H-901 is a “fuel gas combustion device” under Subpart J of 40 CFR 60; and “process heater” under Subpart J of 40 CFR 60, 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-901. ~~for the crude distillation unit. At the request of the Director the owner and/or operator of a source shall install such stack gas monitoring devices as the Director deems necessary to determine compliance with the provisions of 45CSR10. The data from such devices shall be readily available at the source location or such other reasonable location that the Director may specify. At the request of the Director, or his or her duly authorized representative, such data shall be made available for inspection or copying. Failure to promptly provide such data shall constitute a violation of this rule.~~ [45CSR§10-8.2.a. and 45CSR13: Permit R13-2334, 4.1.10.]

- a. Emissions from Emission Point H-901 shall not exceed the following limits:

Emission Limits for Heater H-901		
Pollutant	Emission Limits	
	TPM	TPY

Commented [CG14]: The size is below 40 mmbtu/hr so NOx requirements are **not** triggered. However, this heater was not modified with respect to NOx so technically it's not as of yet affected facility under Ja for NOx. To avoid confusion, recommend not indicating as Ja process heater. See Title V Renewal application for more details.

“H-701 and Boiler C were authorized to fire fuel gas by R13-23340 issued on March 18, 2010. Based on the modification definition the SO₂/H₂S provisions of NSPS Ja are applicable (i.e., no increase in NOX triggering modification).”

Commented [CG15]: DHT heater.

CO	0.42	4.22
NO _x	0.30	3.01
PM ₁₀	0.08	~~0.7990~~
PM _{2.5}	0.08	~~0.7990~~
VOC	0.12	1.20

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
 Annual emission limit – TPY shall be based on 12-month rolling total basis.

- b. The heater shall not burn “fuel gas” that does not meet the stated standards in Conditions 4.1.16. and 4.1.17. of this permit. *Compliance with this streamlined requirement ensures compliance with the SO₂ lb/hr limit in 45CSR§10-3.1.5*

[45CSR`10-5.1.; 45CSR16; 40 CFR §60.104(a)(1); 45CSR13: Permit R13-2334, 4.1.13.]

Boilers A and B

- 4.1.14. Heater H-1101 is a “indirect heat exchanger” under Subpart Dc of 40 CFR60, and a “Fuel Burning Unit” under 45CSR2, and 45CSR10. The following conditions and requirements are specific to Heater H-1101 for the hydrogen plant: ~~The combined emissions from Boiler A and Boiler B (Emission Point ID Nos. A & B, which is a common stack) shall not exceed those listed below. NO_x limits (based on a three hour averaging period) for each boiler shall be as follows: Boiler A – 0.058 lb/MMBtu and Boiler B – 0.058 lb/MMBtu.~~

- a. Emissions from Emission Point H-1101 shall not exceed the following limits:

Pollutant	Emission Limits for Heater H-1101	
	Emission Limits	
	~~Tons per month (TPM)~~	~~Tons per year (TPY)~~
CO	~~0.17 11.51~~	~~1.70 115.07~~
NO _x	~~0.68 8.1~~	~~6.80 81.04~~
PM	~~1.04~~	~~10.42~~
SO ₂	~~0.81~~	~~8.06~~
PM ₁₀	0.17	1.70
PM _{2.5}	0.17	1.70
VOC	~~0.13 0.75~~	~~1.25 7.53~~

TPM – Tons per month shall be based on total emissions of the pollutant for the calendar month.
 Annual emission limit – TPY shall be based on 12-month rolling total basis.

[45CSR13: Permit R13-2334, 4.1.13.]

- b. PM emissions from the Emission Point “H-1101” shall not exceed 0.47 pound per hour on a 6-hour average basis. *Compliance with this streamlined PM limit will ensure compliance with 45CSR§2-4.1.2.*
- c. Heater H-1101 shall not exhibit visible emissions from Emission Point “H-1101” greater than 10% on a six (6) -minute average basis.

Commented [CG16]: The previous permit limit was for filterable PM only and was not based on the AP 42 factor for both filterable and condensable. Converting the existing PM limit to PM10/PM2.5 could be problematic due to the condensable portion. Recommend aligning the PM10/PM2.5 limits with AP 42 calculation for filterable + condensable.

27.5 MMBtu/hr x 0.0075 lb/MMBtu x 8,760 hr/yr / 2,000 lb/ton.

d. This heater shall be limited to firing exclusively on natural gas. Therefore, this heater is exempt from the requirements of subdivision 8.1.1. and subsections 8.2 of 45CSR2; and the requirements of section 8 of 45CSR10.

e. SO₂ emissions from the Emission Point "H 1101" shall not exceed 120.8 pound per hour.

[45CSR§2-3.1.; 45CSR§2-4.1.2.; 45CSR§2-8.4.2.; 45CSR§10-3.1.5.; 45CSR§10-10.3; 45CSR13: Permit R13-2334, 4.1.14.]

4.1.15. a. The permittee shall not allow any "fuel gas combustion device" (boiler or process heater) to burn any "refinery fuel gas" (RFG) that contains hydrogen sulfide (H₂S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. Emissions from the operation of Boilers A & B, shall not exceed a total emission rate of 264 lbs. SO₂/hr.

~~[CO-SIP-95-1 – Condition IV.3.B.b. (SIPed)]~~

b. For each exceedance of the 162 ppm H₂S standard in the above paragraph that results in a SO₂ discharge from a "fuel gas combustion device" subject to this standard greater than 500 pounds than the amount that would be if the H₂S emissions standard had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter. Then, the permittee shall conduct a "root cause analysis" and "corrective action analysis" as soon as possible, but no later than 45 days after such exceedance and implement "corrective action" in accordance with 40 CFR §60.103a(e) if applicable.

c. The corrective action(s) identified in the corrective action analysis conducted pursuant to 40 CFR §60.103a(d) shall be implemented in accordance with the applicable requirements in 40 CFR §60.103a(e)(1) through (3) as follows:

i. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in 40 CFR §60.108a(c)(6)(ix).

ii. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

iii. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in 40 CFR §60.108a(c)(6)(x).

[45CSR16; 40 CFR §102a(g)(1)(ii), §§60.103a(c) & (c)(2), §60.103a(d), §60.103a(e); 45CSR13: Permit R13-2334, 4.1.15.]

4.1.16. The permittee shall not allow any "fuel gas combustion device" (process heater) to burn any "fuel gas" that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 grains/dscf) determined hourly on a 3-hour rolling average basis. Any modifications or replacement of the stacks from Boilers No. A and B shall comply with the provisions of 45CSR20 "Good Engineering Practice as Applicable to Stack Heights".

Commented [CG17]: Compliance with natural gas only requirement renders this condition unnecessary.

Calculations Basis (§45-10-3.1.5):

3.1 lb/MMBtu x 38.8 MMBtu/hr.

Commented [CG18]: Removing to generically apply to fuel gas combustion devices subject to Ja for future flexibility. It's possible to have a fuel gas combustion device that is not a boiler or process heater.

Commented [CG19]: Removing to generically apply to fuel gas combustion devices subject to J for future flexibility. Note that boilers are currently subject to this requirement. However, it's possible to have a fuel gas combustion device that is not a boiler or process heater.

[CO-SIP-95-1 – Condition IV.10. (SIPed)]

[45CSR`6; 40 CFR §60.104(a)(1), §60.105(e)(3)(ii); 45CSR13: Permit R13-2334, 4.1.16.]

Boiler-C

- 4.1.17. ~~The permittee shall not combust any refinery fuel gas (refinery process gas) stream that contains hydrogen sulfide in a concentration greater than 50 grains per 100 cubic feet of gas. Compliance with this hydrogen sulfide concentration limit shall be based on 3-hour block averaging time. Boiler C shall be equipped with low NO_x burners. NO_x limits (based on a three-hour averaging period) shall be 0.050 lb/MMBTU. Emissions from Boiler C (Emission Point ID No. C) shall not exceed the limits in the following table. Compliance with the NO_x limit shall demonstrate compliance with the less stringent limit of Permit R13-2334. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.~~

Pollutant	Emission limit	
	Tons per month (TPM)	Tons per year (TPY)
CO	3.43	34.27
NO _x	2.08	20.81
PM	0.31	3.1
SO ₂	0.24	2.41
VOC	0.22	2.24

~~[45CSR13: Permit R13-2334, 4.1.14., 4.1.15.; 45CSR§10-3.1.e.]~~

[45CSR§§10-5.1 and 5.4.; 45CSR13: Permit R13-2334, 4.1.17.]

Heaters H-101R, H-102R, and H-501R

- 4.1.18. ~~At all times, including periods of start-ups, shutdowns and malfunctions, the permittee shall, to the extent practicable, maintain and operate any of the permittee “fuel burning unit(s)” Boilers A, B, and C; duct burner for TDB01; and H-1101; “fuel gas combustion devices,” and “process heaters,” 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 Director and/or Administrator which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source. Process heaters H-101R, H-102R, and H-501R shall be equipped with low NO_x burners. NO_x limits (determined daily on a 30-day rolling averaging basis) on H-101R shall be 40ppmv (dry basis, corrected to 0 percent excess air). Combined emissions from H-101R and H-102R, and emissions from H-501R shall not exceed those listed below.~~

Pollutant	H-101R and H-102R		H-501R	
	TPM	TPY	TPM	TPY
CO	1.23	12.31	0.15	1.5
NO _x	2.67	26.68	0.33	3.27
PM _{2.5}	0.86	3.06	0.04	0.35
PM ₁₀	0.86	3.06	0.04	0.35

PM	0.86	3.06	0.04	0.38
SO ₂	1.09	10.88	0.11	1.12
VOC	0.21	2.05	0.03	0.25

~~[45CSR13: Permit R13-2334, 4.1.15., 4.1.16, 45CSR16, 40 CFR §60.102a(g)(2)(i)(A)]~~

[\[45CSR§2-9.2., 45CSR13: Permit R13-2334, 4.1.18., 45CSR16, and 40 CFR §60.11\(d\)\]](#)

Heaters H-201, H-441, and H-701

4.1.19. ~~The conditions and requirements in the following subdivisions are specific to the Fluid Cooler (ID CCT01): Emissions from heaters H-201, H-701, and H-441 shall not exceed those listed in the following table. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.~~

- a. [Emissions of PM, PM₁₀, and PM_{2.5} shall be controlled with a 0.001% of the recirculating water rate drift eliminator or equivalent control technology.](#)
- i. [PM emissions emitted to the atmosphere from the Fluid Cooler shall not exceed 0.19 lb/hr and 0.82 TPY.](#)
- ii. [PM₁₀ and PM_{2.5} emissions emitted to the atmosphere from the Fluid Cooler shall not exceed 0.01 lb/hr and 0.01 TPY.](#)
- b. [Make-up water for the Fluid Cooler shall not have a total dissolved solids concentration greater than 18,500 ppmw at any time.](#)

Pollutant	H-201		H-701		H-441	
	TPM	TPY	TPM	TPY	TPM	TPY
CO	0.43	2.38	0.44	4.36	0.44	4.44
NO _x	0.28	2.78	0.11	1.06	0.53	5.28
PM	0.02	0.22	0.04	0.39	0.04	0.40
SO ₂	0.08	0.77	0.14	1.4	0.01	0.03
VOC	0.02	0.16	0.03	0.29	0.03	0.29

~~[45CSR13: Permit R13-2334, 4.1.20., 45CSR§10-3.1.e.]~~

[\[45CSR13: Permit R13-2334, 4.1.19.\]](#)

~~4.1.20. Heater H-441 shall be limited to combusting natural gas only.~~

~~[CO-SIP-95-1 – Condition IV.8. (SIPed); 45CSR13: Permit R13-2334, 4.1.21.]~~

~~4.1.21. The vacuum fractionator heater, H-701, shall be fired only with natural gas and/or treated refinery fuel gas that contains hydrogen sulfide in a concentration not to exceed 10 grains/100 dry standard cubic feet of gas; and emissions of sulfur dioxide shall not exceed 0.8 lbs/mmBtu.~~

~~[CO-SIP-95-1 – Condition IV.6. (SIPed)]~~

Heaters H-500S and H-600S

4.1.22. Emissions from H-500S and H-600S heaters shall not exceed those listed in the following table. Note: “S” means multiple heaters with emissions exiting a common emission point.

Pollutant	H-500S		H-600S	
	TPM	TPY	TPM	TPY
CO	2.02	20.16	1.5	15.01
NO _x	2.96	29.58	2.14	21.44
PM _{2.5}	0.18	1.76	n/a	n/a
PM ₁₀	0.18	1.80	n/a	n/a
PM	0.19	1.90	0.14	1.36
SO ₂	0.72	7.21	0.48	4.83
VOC	0.13	1.31	0.1	0.98

[45CSR13: Permit R13-2334, 4.1.22.]

Heaters H-901 and H-1101

4.1.23. Emissions from the DHT Heater (H-901) and Hydrogen Plant Heater (H-1101) shall not exceed those listed in the following table.

Pollutant	H-901		H-1101	
	TPM	TPY	TPM	TPY
CO	0.42	4.22	0.17	1.70
NO _x	0.30	3.01	0.68	6.80
PM	0.08	0.79	0.17	1.70
SO ₂	0.27	2.72	0.01	0.10
VOC	0.12	1.20	0.13	1.25

[45CSR13: Permit R13-2334, 4.1.23.]

4.1.24. Heater H-1101 shall be limited to combusting natural gas only.

[45CSR13: Permit R13-2334, 4.1.24.]

Boilers A, B, and C, Heaters H-201, H-500S, H-600S, H-701, and H-901

4.1.25. The permittee shall comply with the emission limitations set forth in 40 CFR 60 Subpart J on and after the date on which the initial performance test, required by 40 CFR § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

[40 CFR § 60.104, 45CSR§16-4.1; 45CSR13: Permit R13-2334, 4.1.26.]

Heaters H-101R, H-102R, H-500S, and H-501R

4.1.26. The permittee shall comply with the emission limitations set forth below on and after the date on which the initial performance test, required by 40 CFR §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first.

The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

~~[45CSR16, 40 CFR §§ 60.102a (a) and (g)(1)(ii), 45CSR13: R13-2334, 4.1.17.]~~

- 4.1.27. c. Each owner or operator that operates a fuel gas combustion device subject to 40 CFR Part 60 Subpart Ja shall conduct a root cause analysis and a corrective action analysis for the following condition specified in 40 CFR §§ 60.103a (c) (2):

For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in 40 CFR § 60.102a (g) (1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

- d. A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3). Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 40 CFR §§ 60.103a (d) (1).

1. If a single continuous discharge meets any of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3) for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

5. If discharges occur that meet any of the conditions specified in 40 CFR §§ 60.103a (c) (1) through (3) for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

- e. The owner or operator of a fuel gas combustion device subject to 40 CFR Part 60 Subpart Ja shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to 40 CFR § 60.103a (d) in accordance with the applicable requirements in 40 CFR §§ 60.103a (e) (1) through (3):

1. All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If permittee concludes that corrective action should not be conducted, the permittee shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in 40 CFR § 60.108a (c) (6) (ix).

2. For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the permittee shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

3. No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the permittee shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in 40 CFR § 60.108a (c) (6) (x).

~~j.—Alternative means of emission limitation.~~

- ~~1.— Each permittee subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in 40 CFR § 60.103a.~~
- ~~2.— Determination of equivalence to the design, equipment, work practice or operational requirements of 40 CFR § 60.103a will be evaluated by the following guidelines:~~
 - ~~i.— Each permittee applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.~~
 - ~~ii.— For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.~~
 - ~~iii.— For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.~~
 - ~~iv.— Each permittee applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.~~
 - ~~v.— The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in 40 CFR § 60.103a (j) (2) (iv).~~
 - ~~vi.— The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.~~
- ~~3.— A permittee may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.~~
- ~~4.— Approval of the application for equivalence to the design, equipment, work practice or operational requirements of 40 CFR § 60.103a will be evaluated by the following guidelines:~~
 - ~~i.— After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.~~
 - ~~ii.— After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.~~

~~iii. Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h) (1) of the CAA.~~

~~5. Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of 40 CFR § 60.103a. The Administrator will make an equivalence determination according to the provisions of 40 CFR §§ 60.103a (j) (2) through (4).~~

~~[45CSR16, 40 CFR § 60.103a(e)(2), (d)(1), (d)(5), (e), and (j), 45CSR13: R13-2334, 4.1.18.]~~

Portable Boiler

~~4.1.20. 4.1.28.~~ Emissions from the Portable Boiler shall not exceed the following:

CO		NO _x		PM		SO ₂		VOCs		HAPs	
lb/hr	tpy	lb/hr	tpy	lb/hr*	tpy	lb/hr*	tpy	lb/hr	tpy	lb/hr	tpy
8.23	11.06	4.90	6.58	0.74	1.00	0.06	0.08	0.54	0.72	0.01	0.02

~~* Compliance with these streamlined PM and SO₂ lb/hr limits will ensure compliance with 45CSR§2-4.1.2. and 45CSR§10-3.1.5. respectively.~~

~~[45CSR§2-4.1.2.; 45CSR§10-3.1.5.; 45CSR13: R13-2334, 4.1.3.a, 4.1.27.]~~

~~4.1.21. 4.1.29.~~ The portable boiler shall burn pipeline quality natural gas only.

~~[45CSR13: R13-2334, 4.1.3.b, 4.1.28.]~~

~~4.1.22. 4.1.30.~~ The portable boiler shall only operate at the following times:

- ~~i. When either Boilers A, B or C are offline; or~~
- ~~ii. Prior to the shutdown of Boiler A, B, or C only while the portable boiler is in startup mode; or~~
- ~~iii. When Boiler A, B, or C is in startup mode.~~

~~[45CSR13: R13-2334, 4.1.3.c, 4.1.29.]~~

~~4.1.23. 4.1.31.~~ The portable boiler shall not operate more than 2,688 hours per year. Compliance with this condition shall be based on a 12 month rolling total.

~~[45CSR13: R13-2334, 4.1.3.d, 4.1.30.]~~

~~4.1.24. 4.1.32.~~ The portable boiler shall not be attached to a foundation and shall not be onsite for more than 180 consecutive days.

~~[45CSR13: R13-2334, 4.1.3.e, 4.1.31.]~~

~~4.1.25. 180 days after the initial startup of TBD01 (combustion turbine w/duct burner), the permittee shall not longer be authorized to bring on site and operate a portable boiler under this permit.~~

~~[45CSR13: R13-2334, 4.1.3.f.]~~

4.2. Monitoring Requirements

All Boilers and Heaters

4.2.1. ~~For the purpose of verifying compliance for the boilers and heaters, which has been identified in Section 4.1, that is subject to the opacity limits of 45CSR2-3.1, the permittee shall conduct visible emission checks and/or opacity monitoring and recordkeeping in accordance with the following. Visual emission checks of each emission point subject to an opacity limit shall be conducted during periods of facility operation for a sufficient time interval to determine if the unit has visible emissions using 40 CFR 60 Appendix A, Method 22. If natural gas is being combusted, the visual emissions checks shall be conducted monthly. If fuel oil is being combusted, the visual emissions checks shall be conducted weekly. If visible emissions are identified during the survey, or at any other time, the permittee shall take corrective action to minimize the emissions immediately. If during these checks, or at any other time, visible emissions are observed, a visible emission evaluation shall be conducted in accordance with 40 CFR 60 Appendix A, Method 9. A Method 9 evaluation shall not be required if the visible emission condition is corrected in a timely manner. A record of each visible emission check required above shall be maintained on site for a period of no less than five (5) years. Said record shall include, but not be limited to, the date, time, name of emission unit, the applicable visible emissions requirement, the results of the check, what action(s), if any, was/were taken, the name of the observer, and any data required by 40 CFR 60 Appendix A, Method 22 or Method 9.~~

a. ~~The visible emission check shall determine the presence or absence of visible emissions. 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 Part 60, Appendix A, Method 22 or from the lecture portion of the 40 CFR Part 60, Appendix A, Method 9 certification course.~~

b. ~~Visible emission checks shall be conducted at least once per calendar year of the respective emission point for Boilers A, B, and C; and Heater H-6001101. These checks shall be performed at each source (stack, transfer point, fugitive emission source, etc.) for a sufficient time interval, but no less than six (6) minutes, to determine if any visible emissions are present. Visible emission checks shall be performed during periods of normal facility operation and appropriate weather conditions.~~

c. ~~If visible emissions are present at a source(s) during the visible emission check, the permittee shall conduct an opacity reading at that source(s) using the procedures and requirements of U.S. EPA Method 9 as soon as practicable, but within seventy-two (72) hours of the visual emission check that detected visible emissions. Records of such checks and Method 9 observations shall be maintained in accordance with Condition 3.4.2 of this permit.~~

[45CSR13:- Permit R13-2334, 4.2.1.]

~~Boilers A and B, All Heaters (except H-101R, H-102R, H-501R, H-901 and H-1101)~~

4.2.2. ~~For Boilers A and B, All Heaters (except H-101R, H-102R, H-501R, H-901 and H-1101):~~ Compliance with the emission limitations of CO-SIP-95-1 shall be based upon the averaging time and compliance determination methods established within [Section V of CO-SIP-95-1](#) ~~in Sections 4.2.4. through 4.2.7., and 4.2.10. of this permit.~~

[CO-SIP-95-1 - Condition V.1. (SIPed)]

Commented [CG20]: Only units subject to Rule 2 require the visual checks.

Boilers A and B

- 4.2.3. For Boilers A and B: The permittee shall monitor compliance with 45CSR§2-3 in an approved monitoring plan (see Appendix A) for each emission unit. Such plans shall include, but not be limited to, one or more of the following: continuous measurement of emissions, monitoring of emission control equipment, periodic parametric monitoring, or such other monitoring as approved by the Director.
[45CSR§2-8.2.; 45CSR13; Permit R13-2334, 4.1.12.]
- 4.2.4. The permittee shall monitor O₂ of the exhaust from Heater H-101R as alternative to monitoring NO_x emissions as allowed under Subpart Ja of 40 CFR60 for natural draft process heater with a heat input between 40 to 100 MMBtu/hr in accordance with the following requirements for the purpose of demonstrating compliance with Condition 4.1.5.b. of this permit: ~~Compliance with the sulfur dioxide emission limitations established in Section 4.1.15. for gas-fired boiler Nos. A and B shall be demonstrated in accordance with the following provisions:~~
- a. The permittee shall install, operate, and maintain O₂ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O₂ monitor must be selected between 10 and 25 percent, inclusive.
 - b. The permittee shall conduct performance evaluations of each O₂ monitor according to the requirements in 40 CFR §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to 40 CFR60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.
 - c. The permittee shall comply with the quality assurance requirements in Procedure 1 of appendix F to 40 CFR60 for each O₂ monitor, including annual accuracy determinations for O₂ monitors, and daily calibration drift tests.
 - d. For Heater H-101R, the permittee shall determine excess NO_x emissions as each day during which the concentration of O₂ as measured by the O₂ continuous monitoring system required under this condition exceeds the O₂ operating limit or operating curve determined during the most recent biennial performance test as required in Condition 4.3.1 of this permit.
 - e. The permittee shall maintain records of the measured readings, performance evaluations, annual accuracy determinations, daily calibration drift tests and any maintenance performed on the monitoring system/instrument in accordance with Condition 3.4.2. of this permit.
- a. ~~Co-located continuous monitoring systems (for sulfur dioxide and oxygen) shall be installed, calibrated, maintained and operated to measure the concentration of sulfur dioxide and oxygen in the combustion gases discharged from these boilers. The continuous monitoring systems and programs shall comply with the requirements of Sections 4.2.5. and 4.2.6.~~
- b. ~~Following installation of the continuous monitoring system, compliance shall be determined based upon a rolling three (3) hour average of measured sulfur dioxide concentrations and procedures approved by the Director to calculate hourly mass emissions.~~

e.—During any period after June 1, 1995 in which either of these boilers is operated without its continuous emission monitoring system in proper operation, the Company shall fire only natural gas or desulfurized refinery fuel gas in the boiler.

**[CO-SIP-95-1 – Condition V.3. (SIPed) (During fuel oil combustion only, see Section 4.1.6.)]
[45CSR16; 40 CFR §§60.107a(c), (c)(3) – (c)(5) and (i)(5); 45CSR13: Permit R13-2334, 4.2.4.]**

4.2.5.—Installation, calibration, maintenance and operation of the continuous emission monitoring systems required under Section 4.2.4., shall comply with the following provisions under 40 CFR Part 60:

a. Part 60.13(a)	i. Part 60.13(j)
b. Part 60.13(e)	j. Part 60.45(e)
c. Part 60.13(d)(1) ———	k. Part 60.45(e)
d. Part 60.13(e)(2)	l. Part 60.45(f)
e. Part 60.13(f) —	m. Part 60.46(b)(4)
f. Part 60.13(g)	n. Part 60; Appendix A, Methods 6, 6A and 6B
g. Part 60.13(h)	o. Part 60; Appendix B, Performance Specification 2
h. Part 60.13(i) —	p. Part 60; Appendix B, Performance Specification 3

Where the term “Administrator” (USEPA) is used within any of the adopted 40 CFR Part 60 provisions, the term shall mean the Director.

[CO-SIP-95-1 – Condition V.5. (SIPed)]

4.2.6.—All continuous emission monitoring data required to be collected under Section 4.2.4. shall be quality assured in accordance with 40CFR part 60, Appendix F Quality Assurance Procedures.

[CO-SIP-95-1 – Condition V.7. (SIPed)]

Boilers A and B, Heaters H-701, H-500S, H-600S

4.2.5. ~~4.2.7.~~ Sources of sulfur dioxide emissions subject to CO-SIP-95-1 shall demonstrate compliance with the emission standards set forth in subsections IV .3, IV .4 , IV .5, IV .6, IV .7, IV .9 and IV .10 of CO-SIP-95-1 Sections 4.1.15., 4.1.21., and 5.1.5., using data collected in accordance with this section V. of CO-SIP-95-1 and reference emissions test procedures in 40 CFR Part 60, Appendix A, Methods 6, 6A, 6B, and 19.

[CO-SIP-95-1 - Condition V.8. (SIPed)]

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701, H-901

4.2.8.—The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) shall demonstrate compliance with sections 3, 4 and 5 of 45CSR10 by testing and /or monitoring in accordance with one or more of the following: 40 CFR Part 60, Appendix A, Method 6, Method 15, continuous emissions monitoring systems (CEMS) or fuel sampling and analysis as set forth in an approved monitoring plan for each emission unit (see Appendix A).

[45CSR§10-8.2.e.; 45CSR13: Permit R13-2334, 4.1.11.]

Boilers A, B, and C, Heaters H-201, H-600S, H-701, H-901

4.2.6. ~~4.2.9.~~ To demonstrate compliance with Conditions 4.1.15., 4.1.16., and 4.1.17., the permittee shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration

by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

~~To demonstrate compliance with Section 4.1.12, the permittee shall install, certify, calibrate, maintain, and operate a fuel gas CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B.~~

- a. This instrument shall be installed, operated, and maintained according to Performance Specification 7 to 40 CFR60. The span value for this instrument is 300 ppmv H₂S. *Compliance with this streamlined span value of 300 ppmv H₂S will ensure compliance with 40 CFR §105(a)(4)(i).*

During any period of failure or malfunction of the H₂S monitor system, the permittee shall collect two (2) gas samples of the RFG per eight (8) hour period and determine the H₂S concentration and heating value of each sample through a gas chromatography in accordance with ASTM Method D-1945. The permittee may request approval by the Director of alternative sampling and analytical methods for determination of these parameters during periods when the H₂S monitoring system has failed or malfunctioned.

- b. The permittee shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR§60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to 40 CFR60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR§60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to 40 CFR60.
- c. The permittee shall comply with the applicable quality assurance procedures in appendix F to 40 CFR60 for each H₂S monitor.
- d. Fuel gas combustion devices or flares 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 fuel gas combustion devices or flares.
- e. For the duct burner for the combustion turbine; Boiler C and Heaters H-101R, H-102R, H-501R, H-505R, and H-701, the permittee shall determine excess the arithmetic average of each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under this condition exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under this condition exceeds 60 ppmv.
- f. For Boiler A, Boiler B, Heaters H-201, H-500S (excluding H-505R), H-600S and H-901, the permittee shall determine excess the arithmetic average of all three (3) hour averages during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under this condition exceeds 230 mg/dscm (0.10 gr/dscf).
- g. For Boilers A, B, and C; duct burner for the combustion turbine; and Heaters H-101R, H-102R, H-201, H-501R, H-500S, H-600S, H-701, and H-901, the permittee shall determine each 3-hour block average exceeds 50 grains per 100 scf of gas if there are excess emission identified from paragraphs e. (3-hour standard) or f. of this condition.

- h. For any periods that the excess emissions are determined of the short term (3-hour average) average standards under paragraphs e. and/or f. of this condition, the permittee shall determine the daily SO₂ emissions in terms of lb of SO₂ per hour for Boilers A and B, and lb of SO₂ per MMBtu for Heater H-201, H-500S, H-600S, and H-701 to determine compliance the SO₂ limits of Consent Order CO-SIP-95-1.

All valid hourly reading shall be in reduce into 3-hour averages. Records of all readings, maintenance preformed, calibrations, and audits shall be maintained in accordance with Condition 3.4.2. of this permit.

~~Compliance with the hydrogen-sulfide concentration limit of permit condition 4.1.12. shall be demonstrated using the continuous monitor as follows:~~

- a. ~~An instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.~~
- i. ~~The span value for this instrument is 425 mg/dscm H₂S.~~
- ii. ~~Fuel gas combustion devices 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.~~
- iii. ~~The performance evaluations for this H₂S monitor under 40 CFR § 60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations~~

~~Compliance with this condition will ensure shall demonstrate compliance with CO-SIP-95-1, Conditions V.3., V.4., V.5., and V.6.~~

~~[45CSR16; 40 CFR §§60.7(f), (f)(1) and (f)(2), §60.105(a)(4)(i), (ii), and (iii), 105(e)(3)(ii), §§107a(a)(2)(i)-(iv), §107a(i)(1)(ii); and 45CSR§16-4.1; 45CSR§10-5.4. and §§10-8.2.3., 8.2.3.a., 8.2.3.a.1.; CO-SIP-95-1 - Conditions V.3. V.4., V.5., V.6., V7 and V.11. (SIPed); 45CSR13: Permit R13-2334, 4.2.2., 4.2.4.]~~

Heaters H-201, H-500S, H-600S

~~4.2.10.—Compliance with the sulfur dioxide emission limitations established in Sections 4.4.12. and 4.4.14. for Process Heater H-201, H-500S, and H-600S shall be determined daily in accordance with the following provisions:~~

- a. ~~Total daily sulfur dioxide emissions for each heater shall be calculated by adding the sulfur dioxide emissions attributable to each fuel fired during all twenty-four (24) hour periods.~~
- b. ~~Sulfur dioxide emissions attributable to the combustion of fuel oil shall be determined by sampling and analyzing the volume of fuel oil fired for sulfur content and heating volume in accordance with applicable ASTM sampling and analytical methods and accurately measuring the volume and mass of fuel oil fired in each heater.~~

~~[CO-SIP-95-1 – Condition V.4. (SIPed) (During fuel oil combustion only, see Section 4.1.6.)]~~

Heaters H-901 and H-1101

~~4.2.7.~~ ~~4.2.11.~~ The permittee shall monitor and record the amount of fuel gas consumed in Heaters H-101R, H-102R, H-201, H-501R, H-500S, H-600S, H-701, H-901 and duct burner for TDB01 through individual volumetric flow meters. Records of the readings, maintenance performed on the instruments, and calibrations shall be maintained in accordance with Condition 3.4.2. of this permit. ~~using flow meters.~~

[45CSR13: Permit R13-2334, 4.2.6.; CO-SIP-95-1 - Condition V.4. (SIPed)]

~~4.2.8.~~ ~~4.2.12.~~ The permittee shall monitor and record the amount of natural gas consumed in heaters H-441 and H-1101 using flow meters. Records of the readings, maintenance performed on the instruments, and calibrations of the instruments shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR13: Permit R13-2334, 4.2.5.]

Boilers A and B

~~4.2.9.~~ ~~4.2.13.~~ To demonstrate compliance with the three-hour average NO_x limit of Section ~~4.1.1.b.~~ ~~4.1.14.~~, the permittee shall install, certify, calibrate, maintain, and operate a CEMS on Boilers A and B to measure NO_x and O₂ in accordance with the requirements of 40 CFR §§60.11, 60.13, and 40 CFR Part 60 Appendices A and F.

[45CSR13: Permit R13-2334, 4.2.3.]

Heaters H-101R, H-102R, H-500S, and H-501R

~~4.2.14. a. — Fuel gas combustion devices subject to H₂S limit.~~

~~The owner or operator of a fuel gas combustion device that is subject to 40 CFR § 60.102a(g)(1) and elects to comply with the H₂S concentration limits in 40 CFR § 60.102a(g)(1)(ii) shall comply with 40 CFR § 60.107a(a)(2).~~

~~2. — The owner or operator of a fuel gas combustion device that elects to comply with the H₂S concentration limits in 40 CFR § 60.102a(g)(1)(ii) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device.~~

~~i. — The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of 40 CFR Part 60 Appendix B. The span value for this instrument is 300 ppmv H₂S.~~

~~ii. — The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR § 60.13 (c) and Performance Specification 7 of 40 CFR Part 60 Appendix B. The owner or operator shall use Method 11, 15, or 15A of 40 CFR Part 60 Appendix A-5 or Method 16 of 40 CFR Part 60 Appendix A-6 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA Method 15A of 40 CFR Part 60 Appendix A-5.~~

~~iii. — The owner or operator shall comply with the applicable quality assurance procedures in 40 CFR Part 60 Appendix F 60 for each H₂S monitor.~~

- iv. Fuel gas combustion devices 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 fuel gas combustion devices.

d. *Process heaters complying with the NO_x heating value-based or mass-based limit.*

The owner or operator of a process heater subject to the NO_x emissions limit in 40 CFR § 60.102a (g) (2) and electing to comply with the applicable emissions limit in 40 CFR § 60.102a (g)(2)(i)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in 40 CFR §§ 60.107a (d)(1) through (4).

1. Except as provided in 40 CFR § 60.107a (d)(8), the owner or operator shall install, operate and maintain each NO_x monitor according to the requirements in 40 CFR §§ 60.107a (c) (1) through (5). The monitor must include an O₂ monitor for correcting the data for excess air.
2. Except as provided in 40 CFR § 60.107a (d)(3), the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of Appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).
3. As an alternative to the requirements in 40 CFR § 60.107a (d)(2), the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of 40 CFR Part 60 Subpart Ja and Equation 10 of 40 CFR § 60.107a. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1,000,000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)}$$

Where:

- F_d = F factor on dry basis at 0 percent excess air, dscf/MMBtu.
X_i = mole or volume fraction of each component in the fuel gas.
MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).
MHC_i = molar heat content, Btu per mole (Btu/mol).
1,000,000 = unit conversion, Btu per MMBtu.

4. The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of 40 CFR Part 60 Appendix B. Any of the following methods shall be used for conducting the relative accuracy evaluations:
 - i. EPA Method 18 of 40 CFR Appendix A-6;
 - ii. ASTM D1945-03 (Reapproved 2010) (incorporated by reference see 40 CFR § 60.17);
 - iii. ASTM D1946-90 (Reapproved 2006) (incorporated by reference see 40 CFR § 60.17);

- iv. —ASTM D6420-99 (Reapproved 2004) (incorporated by reference see 40 CFR § 60.17);
- v. —GPA 2261-00 (incorporated by reference see 40 CFR § 60.17); or
- vi. —ASTM UOP539-97 (incorporated by reference see 40 CFR § 60.17).

i. *Excess emissions:*

For the purpose of reports required by § 40 CFR § 60.7 (c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in 40 CFR § 60.102a (g) are defined as specified in 40 CFR §§ 60.107a (i) (1) through (5). Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (e.g., a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

1. H₂S limits for fuel gas combustion devices. ii. If the owner or operator of a fuel gas combustion device elects to comply with the H₂S concentration limits in 40 CFR § 60.107a § 60.102a (g) (1) (ii), each rolling 3-hour period during which the average concentration of H₂S as measured by the H₂S continuous monitoring system required under 40 CFR § 60.107a (a) (2) exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H₂S continuous monitoring system under 40 CFR § 60.107a (a) (2) exceeds 60 ppmv.

3. Rolling 30-day average NO_x limits for fuel gas combustion devices. Each rolling 30-day period during which the average concentration of NO_x as measured by the NO_x continuous monitoring system required under 40 CFR § 60.107a (c) or (d):

- i. —For a natural draft process heater, 40 ppmv and, if monitored according to 40 CFR § 60.107a (d), 0.040 lb/MMBtu;

[45CSR16, 40 CFR §§ 60.107a(a)(2)(i) through (iv), (d)(1) through (4), (i)(1)(ii), and (i)(3)(i), 45CSR13: R13-2334, 4.2.7.]

Portable Boiler

- 4.2.10. 4.2.15. To demonstrate compliance with the requirements of 4.1.23, 4.1.31, the permittee shall monitor the number of hours of operation of the Portable Boiler on a monthly basis.

[45CSR13: R13-2334, 4.2.7, 4.2.8.]

- 4.2.11. To demonstrate compliance with the NO_x emission limits of Conditions 4.1.4.a.i. and 4.1.4.f., the permittee shall install, certify, calibrate, maintain, and operate a CEMS to determine NO_x emissions from the combustion turbine with duct burner accordance with the following requirements.

- a. Each NO_x diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. Alternatively, a NO_x diluent CEMS that is installed and certified according to appendix A of 40 CF 75 is acceptable for use under 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 for each type of fuel shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to 40 CFR 75 are acceptable for use under this condition.
- 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. For the determination of mass NO_x emissions, the permittee shall install, calibrate, maintain, and operate according to manufacturer's written instructions a flow meter measuring the exhaust flow from emission point TDB01.
- f. The permittee shall develop and keep on-site a quality assurance (QA) plan for all the continuous monitoring equipment described in this condition. For the CEMS and fuel flow meters, the permittee may, with Director's 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.
- g. Records of readings, calibrations, performance evaluations, quality assurance tests/checks, and maintenance performed shall be maintained in accordance with Condition 3.4.2.

[45CSR16; 40 CFR §60.7(f), §§60.4333(b) & (b)(1), §60.4345; 45CSR13: R13-2334, 4.2.8.]

4.2.12. To demonstrate compliance with the SO₂ emission standard of Condition 4.1.4.a.ii., the permittee shall sample and analyze the refinery fuel gas each operating day that refinery fuel gas is combusted by duct burner associated with TDB01.

- a. A representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see 40 CFR §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see 40 CFR§60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see 40 CFR §60.17).
- b. The fuel analysis required in this condition may be performed either by the permittee, or a service contractor retained by permittee. The collected samples shall be analyze to determine the total sulfur content of the refinery fuel gas using: ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17).

If the permittee satisfies the criteria under 40 CFR §60.4370(c), the permittee may switch from the daily operating day sampling schedule, as required in this condition, to one of the two "custom schedules" as prescribed in 40 CFR §60.4370(c).

Records of the analyses, to include the date/time when the sample was taken and analyzed and chain of custody of the sample shall be maintained in accordance with Condition 3.4.2. of this permit.

Excess SO₂ emissions are for each operating hour that the duct burner is combusting refinery fuel gas in the period beginning on the date and hour of any sample for which the sulfur content of the refinery fuel gas exceeds the applicable limit in Condition 4.1.4.a.ii. and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

As an alternative to the above monitor requirements, the permittee may elect to utilize the daily average H₂S concentration readings of the refinery fuel gas from the H₂S monitor as required in Condition 4.2.6.e. and convert the daily average H₂S concentration into the form of the SO₂ emission standard stated in Condition 4.1.4.a.ii. For the purposes of the conversion, the permittee shall assume a ratio of 1:1 for H₂S to total sulfur. The permittee shall determine excess SO₂ emissions as outline in 40CFR§60.4385 for each reporting period (if any) and report such excess SO₂ emissions in accordance with 40CFR§60.4375(a) and Condition 3.5.3.

[45CSR16; 40 CFR §60.7(f), §60.4373(b), §60.4370(c), §4385(a), §60.13(i) and Approval Letter of Ergon-West Virginia Inc. Request for Regulatory Applicability Determination: Exemption from NSPS KKKK SO₂ Limits for Sources Subject to NSPS Ja, Dated April 21, 2025; 45CSR13: R13-2334, 4.2.9.]

- 4.2.13. For determining compliance with this emission limit in Condition 4.1.19., the permittee shall monitor cooling water flow rate continuously and the concentration of total dissolved solids contained in the make-up water of the fluid cooler or specific conductivity on a daily basis when the fluid cooler is operating. If the permittee uses a correlation curve or ratio between total dissolve solids concentration and specific conductivity, the Director or his/her representative may request the permittee verify the correlation at any reasonable time with just cause. The permittee shall determine the PM, PM₁₀, and PM_{2.5} emissions from the fluid cooler using a method that accurately predicts these specific pollutants from the fluid cooler. Such determination shall be conducted monthly. Records of such monitoring and determinations shall be maintained in accordance with Condition 3.4.2. of this permit.
[45CSR13: R13-2334, 4.2.10.]

4.3. Testing Requirements

Heaters H-101R, H-102R, H-500S, and H-501R

- 4.3.1. The permittee shall conduct biennial (once every 2 years) performance tests according to the requirements in 40 CFR §60.104a(i), establish a maximum excess O₂ operating limit or operating curve ~~according to~~ for Heater H-101R according to the requirements in §60.104a(i)(6) and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of 40 CFR §60.107a to demonstrate compliance. If an O₂ operating curve is used (i.e., if different O₂ operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of 40 CFR §60.107a, respectively.
- a. ~~i.~~—The permittee shall determine compliance with the NO_x emissions limits in 40 CFR §60.102a (g) for a fuel gas combustion device according to the following test methods and procedures:
1. —40 CFR Part 60 Appendix A-1, Method 1 for sample and velocity traverses;
 2. —40 CFR Part 60 Appendix A-1, Method 2 for velocity and volumetric flow rate;

3. ~~40 CFR Part 60 Appendix A-2, Method 3, 3A, or 3B for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-2, Method 3B;~~

5. ~~40 CFR Part 60 Appendix A-4, Method 7, 7A, 7C, 7D, or 7E for moisture content and for the concentration of NO_x calculated as NO₂; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-41, Method 7 or 7C;~~

1. For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in 40 CFR §§60.107a(c)(6) or (d)(8), the owner or operator shall establish the O₂ operating limit or O₂ operating curve based on the performance test results according to the requirements in 40 CFR §§60.104a(i)(6)(i) or (ii), respectively.

i If a single O₂ operating limit will be used:

A. Conduct the performance test following the methods provided in 40 CFR §§60.104a(i)(1), (2), (3) and (5) when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

B. Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs. If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

C. Determine the average O₂ concentration for each test run of a valid test.

D. Calculate the O₂ operating limit as the average O₂ concentration of the three test runs from a valid test.

ii If an O₂ operating curve will be used:

A. Conduct a performance test following the methods provided in 40 CFR §§60.104a(i)(1), (2), (3) and (5) at a representative condition for each operating range for which different O₂ operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired, primarily oil fired, and equally co-fired, i.e., approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

B. Each test will consist of three test runs. Calculate the NO_x concentration for the performance test as the average of the NO_x concentrations from each of the three test runs.

If the NO_x concentration for the performance test is less than or equal to the numerical value of the applicable NO_x emissions limit (regardless of averaging time), then the test is considered to be a valid test.

- C. If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (i.e., when the process heater is firing at 50 percent or less of the rated heat capacity). If O₂ operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.
 - D. Determine the average O₂ concentration for each test run of a valid test.
 - E. Calculate the O₂ operating limit for each operating range as the average O₂ concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.
 - F. Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O₂ operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O₂ operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.
 - G. Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.
2. The owner or operator of a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O₂ limit, as provided in 40 CFR §§60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in §60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.
3. The owner or operator shall use Equation 8 of 40 CFR §60.104a to adjust pollutant concentrations to 0-percent O₂ or 0- percent excess air.
- b. ~~f.~~ The permittee shall determine compliance with the applicable H₂S emissions limit in 40 CFR §60.102a (g)(1) for a fuel gas combustion device according to the following test methods and procedures:
- 1. ~~40 CFR Part 60 Appendix A-1, Method 1 for sample and velocity traverses;~~
 - 2. ~~40 CFR Part 60 Appendix A-1, Method 2 for velocity and volumetric flow rate;~~

Commented [CG21]: Consider changing this section to 4.3.2, and renumbering subsequent sections. H₂S test procedures should be separate and distinct from NO_x stack testing and O₂ monitoring.

~~3. 40 CFR Part 60 Appendix A-2, Method 3, 3A, or 3B for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR § 60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-2, Method 3B;~~

[1.](#) ~~4.~~ 40 CFR Part 60 Appendix A-5, Method 11, 15, or 15A or 40 CFR Part 60 Appendix A-6, Method 16 for determining the H₂S concentration for affected plants using an H₂S monitor as specified in 40 CFR §60.107a (a) (2). The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-5, Method 15A. The permittee may demonstrate compliance based on the mixture used in the fuel gas combustion device or for each individual fuel gas stream used in the fuel gas combustion device.

- i For 40 CFR Part 60 Appendix A-5, Method 11, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H₂S may necessitate sampling for longer periods of time.
- ii For 40 CFR Part 60 Appendix A-5, Method 15, at least three injects over a 1-hour period constitutes a run.
- iii For 40 CFR Part 60 Appendix A-5, Method 15A, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see 40 CFR §60.17) is an acceptable alternative to EPA 40 CFR Part 60 Appendix A-5, Method 15A.
- iv If monitoring is conducted at a single point in a common source of fuel gas as allowed under 40 CFR §60.107a (a) (2) (iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

[45CSR16, 40 CFR §§~~60.104(a)(6), (i)(7), (i)(8)~~ and (j), [§60.107\(c\)\(6\)](#); 45CSR13, R13-2334, ~~4.1.19, and 4.3.1.~~]

Boilers A and B, Heaters H-201, H-701, H-500S, H-600S

- 4.3.2. [For Boilers A and B, Heaters H-201, H-701, H-500S, H-600S:](#) Any source for which compliance with sulfur dioxide emissions limitations are not demonstrated using continuous emission monitoring systems, must demonstrate compliance in accordance with Section [4.2.5](#), ~~4.2.7~~, not less frequently than semi-annually. At least three test runs, each with sufficient samples to characterize a two-hour period representative of normal source operation, shall be required for each compliance demonstration using the reference test procedures specified in Section [4.2.5](#), ~~4.2.7~~. The Director may order any person subject to CO-SIP-95-1 to conduct or have conducted an emissions test at any time that he or she has reason to believe that an emission limitation may be exceeded. The semi-annual tests shall otherwise be scheduled as ordered by or in consultation with the Director. No tests shall be required for units burning only natural gas.

[CO-SIP-95-1 - Condition V.9. (SIPed)]

Boilers A, B, and C, Heaters H-201, H-701, H-500S, H-600S, H-901

- 4.3.3. ~~The permittee shall conduct an initial performance test within 60 days after achieving the maximum production rate at which the TDB01 will be operated, but not later than 180 days after the initial startup of TDB01 and subsequent performance test on an annual basis (no more than 14 calendar months following the previous performance) for demonstrating compliance with the NO_x standard in Condition 4.1.4.a.i. in accordance with the 40 CFR §§60.4400(a) and the requirements of Condition 3.3.1. During any period of failure or malfunction of the hydrogen sulfide continuous emission monitoring system required under Section 4.2.9., H₂S concentrations of the refinery fuel gas shall be determined by collection of not less than two (2) gas samples per eight (8) hour period which are analyzed by gas chromatography for hydrogen sulfide content, density and heating value in accordance with ASTM Method D-1945. The Company may request approval by the Director of alternative sampling and analytical methods for determination of these parameters during periods when the H₂S monitoring system has failed or malfunctioned.~~

- a. ~~There are two general methodologies that you may use to conduct the performance tests. For each test run:~~

1. ~~Measure the NO_x concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of 40 CFR Part 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 of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_x emission rate:~~

$$E = \frac{1.194 \times 10^{-7} * (NO_x) * Q_{std}}{P} \quad (\text{Equation 5 of 40 CFR 60, Subpart KKKK})$$

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 § 60.4350(f)(2); or

2. ~~Measure the NO_x and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. 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 this part to calculate the NO_x emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_x emission rate in lb/MWh.~~
- b. ~~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~~

Commented [CG22]: Only an initial performance test is required if CEMS are installed. Subsequent annual performance test is not required for TBD01.

“you must conduct performance tests annually following the initial performance test in order to demonstrate compliance. Alternatively, you may choose to demonstrate continuous compliance with the use of a continuous emission monitoring system (CEMS) or parametric monitoring; if you choose this option, you are not required to conduct subsequent annual performance tests. “ [F. How do I demonstrate compliance?] 71 FR 38482 [Published Document: 06-5945 (71 FR 38482)]

documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

- c. Notwithstanding paragraph b. of this section (i.e., 40 CRR §60.4400(a)(2)), you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of 40 CFR Part 60 if the conditions in 40 CFR §60.4400(a)(3) are met:
- d. 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.
- e. NO_x emissions must be measured after the duct burner. The duct burner must be in operation during the performance test.
- f. Compliance with the applicable emission limit in Condition 4.1.4.a.i. 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.
- g. The permittee may elect to conduct the performance evaluation of the NO_x CEMS as part of the initial performance test (as described in 40 CFR §60.4405) for TDB01 or separately.
- h. The ambient temperature must be greater than 0 °F during the performance test.
- i. Records of such testing shall be maintained in accordance with Condition 3.4.2.

[45CSR16; 40 CFR §60.7(f), §60.8, §§60.4400(a), (b), (b)(2), (b)(4) –(b)(6); 45CSR13, R13-2334, 4.3.2, CO-SIP-95-1 – Condition V.11. (SIPed) (During fuel oil combustion only)]

4.3.4. The permittee shall conduct an initial performance test within 60 days after achieving the maximum production rate at which the TDB01 will be operated, but not later than 180 days after initial startup of TDB01 and subsequent performance test on an annual basis (no more than 14 calendar months following the previous performance) for demonstrating compliance with the SO₂ standard in Condition 4.1.4.a.ii. for each type of gaseous fuel combusted by TDB01 using one of the compliance options in sub-paragraphs a. through d. of this condition. Any fuel combusted by this turbine and subject to the emission standards in 40 CFR §60.102a(g)(1)(ii) is exempt from the testing requirements in this condition.

- a. 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. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR part 75 may be used;
- b. Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see §60.17). The fuel analysis of this section may be performed either by the permittee or a service contractor retained by the permittee. Analyze the samples for the total sulfur content of the fuel using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see 40 CFR §60.17);

- c. [Measure the SO₂ concentration \(in parts per million \(ppm\)\), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers \(ASME\) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide \(incorporated by reference, see §60.17\) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of 40 CFR Part 60, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO₂ emission rate:](#)

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad (\text{Equation 6 of 40 CFR 60, Subpart KKKK})$$

[Where:](#)

- [E = SO₂ emission rate, in lb/MWh](#)
[1.664 × 10⁻⁷ = conversion constant, in lb/dscf-ppm](#)
[\(SO₂\)_c = average SO₂ 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 §60.4350\(f\)\(2\); or](#)

- d. [Measure the SO₂ and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of 40 CFR Part 60. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 \(incorporated by reference, see §60.17\). 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 Part 60 to calculate the SO₂ emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350\(f\) to calculate the SO₂ emission rate in lb/MWh.](#)

[These tests shall be conducted in accordance with Condition 3.3.1. of this permit. The report for each performance test shall be maintained in accordance with Condition 3.4.2. of this permit.](#)

[\[45CSR16; 40 CFR §60.7\(f\), §60.8, §60.4415 and Approval Letter of Ergon-West Virginia Inc. Request for Regulatory Applicability Determination: Exemption from NSPS KKKK SO₂ Limits for Sources Subject to NSPS Ja, Dated April 21, 2025; 45CSR13, R13-2334, 4.3.3.\]](#)

- 4.3.5. Within 12 months after initial startup with no less than 2 months of actual operation of the HRSG producing steam for the facility, the permittee shall conduct a performance test to demonstration compliance with the mass CO, formaldehyde, and non-metal total HAPs limits in Condition 4.1.4.b. Such testing shall be conducted in accordance with Condition 3.3.1. and U.S. EPA Test Method 320 of Appendix A of 40 CFR Part 63, or ASTM D6348-12e1 provided that the test plan preparation and implementation provisions of Annexes A1 through A8 of ASTM D6348-12e1 are followed and the %R as determined in Annex A5 of ASTM D6348-12e1 is equal or greater than 70% and less than or equal to 130%. The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Results} = ((\text{Measured Concentration in Stack})/(\%R)) \times 100$$

Such tests shall be conducted with the unit operating in the combined cycle mode at no less than 90% of the unit's gross electric output and 90% of the steam capacity of the HRSG or within 90% of recorded hourly steam output since initial startup. During the three test runs, the duct burner shall be firing during all periods of the testing at a rate that is represented of future operation of the duct burner.

Other HAPs to be measured as Total HAPs are:

Acetaldehyde	Ethylbenzene	n-Xylene
Acrolein	n-Hexane	p-Xylene
Benzene	Naphthalene	o-Xylene
Phenol	Propylene Oxide	
1,3-butadiene	Toluene	

This test shall consist of three (3) 120 minutes test runs. Records of the testing results; and process data, fuel/heat input, parameters used to determine the status of the SoLoNO_x™ mode of the combustion turbine record during the testing each event shall be maintained in accordance with Condition 3.4.2. of this permit.

[45CSR13, R13-2334, 4.3.4.]

4.3.6. The permittee shall conduct subsequent testing for CO, formaldehyde, and total HAPs limits to demonstrate compliance of the limits in Condition 4.1.4.b. within 180 days when the average utilization of the duct burner is greater than 352,826 MMBtu per year on gross heat input basis over the previous 24 months from the most recent compliance demonstration Said subsequent test shall be conducted as outlined in Condition 4.3.5. of this permit.

As an alternative to conducting subsequent testing as required in the above paragraph, the permittee shall conduct tune-ups of the duct burner for TBD01 26 months from the initial compliance test as required in Condition 4.3.5 and once every 26 months thereafter. Such tune-ups shall be conducted in accordance with the manufacturer's instructions. If no manufacturer's instructions exist, the permittee shall develop a written tune-up procedure which shall include the following as a minimum:

- a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment.
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.
- c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (permittee may delay the inspection until the next scheduled unit shutdown)
- d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, the optimization for NO_x emissions needs to consistent with the manufacturer's NO_x concentration setting point unless otherwise stated in this permit.

- e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. The permittee may need to measure the concentration of CO and O₂ upstream of the duct burner to optimize the emissions of CO from the actual duct burner

Records of these tune-ups shall include the following and maintained accordance with Condition 3.4.2.:

The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the duct burner. If concentrations of NO_x were taken during the tune-up of the unit, record of such measurements shall be included; and

A description of any corrective actions taken as a part of the tune-up.

Should the permittee elect to implement the tune-up work practice as an alternative to the subsequent testing, the permittee shall notify the Director in accordance with Condition 3.5.3, within 12 months following the initial compliance demonstration as required in Condition 4.3.5.

[45CSR13, R13-2334, 4.3.5.]

4.4. Recordkeeping Requirements

All Boilers except the Portable Boiler and Heaters

- 4.4.1. To determine compliance with the emission limits set forth set forth in Conditions 4.1.1., and 4.1.3., the permittee shall keep monthly records of the operating schedule, amount of fuel by type (e.g., refinery gas plus natural gas, natural gas) consumed within the boilers, individually. By no later than the 15th day of the following month, the permittee shall determine the monthly emissions and 12-month rolling total from each respective boiler. Mass NO_x emissions from each boiler shall be based on valid CEM data from the respective unit. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. *Compliance with the streamlined requirements will ensure compliance with CO-SIP-95-1 – Condition IV.3.A. To determine compliance with restrictions set forth in Section 4.1.6., the permittee shall document the frequency, length of time, amount of fuel oil consumed, and estimate of emissions during DOT maintenance and periods of natural gas curtailment in which fuel oil was combusted. To determine compliance with fuel oil sulfur content limits set forth in Section 4.1.6., the permittee shall keep records of the sulfur content of all fuel oil received for the purpose of combustion. Each batch of fuel oil shall have its sulfur content determined by test method ASTM D4294. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement E, Chapter 1.3 may be used to estimate emissions.*

[45CSR§8.3.3.; 45CSR13: R13-2334, 4.4.5, 4.4.4. CO-SIP-95-1 - Condition IV.3.A. (SIPed)]

All Boilers and Heaters Except H-201

- 4.4.2. To comply with the emission limits set forth set forth in Conditions 4.1.5., 4.1.6., 4.1.7., 4.1.8., 4.1.9, 4.1.10., 4.1.11., 4.1.12., 4.1.13., and 4.1.14., the permittee shall determine the monthly emissions and 12-month rolling total emissions from each respective heater by no later than the 15th day of the following month. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. *The operators of fuel burning units shall maintain a periodic exception report for each unit. Such reports shall include, but may not be*

~~limited to the date and time of start-ups and shutdowns. All such requirements, including notification by telephone, telefax, or other such method determined by the Director, shall be deemed to be satisfied when the reports are maintained on site for a period of no less than five (5) years and shall be made available upon request to the Director or his/her duly authorized representative.~~

~~[45CSR§2-8.3.b.; 45CSR13: Permit R13-2334, 4.4.6, 4.4.5.]~~

- 4.4.3. The permittee shall maintain records of the operating schedule and the quantity of fuel consumed ~~by type consumed~~ in each ~~boiler and process heater monthly, at a minimum, fuel burning unit monthly, at a minimum,~~ but may record it more often at the discretion of the permittee.

~~[45CSR16; 40 CFR §60.48(g)(3); 45CSR§2-8.3.3.e.; 45CSR13: Permit R13-2334, 4.4.4, 4.4.6.]~~

Boilers A, B, and C, Heaters H-101R, H-102R, H-500S, H-501R, H-600S, H-701

- 4.4.4. The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) subject to 45CSR§§10-3, 4 or 5 shall maintain on-site a record of all required monitoring data as established in a monitoring plan (see Appendix A) pursuant to 45CSR§10-8.2.3. e. Such records shall be made available to the Director or his duly authorized representative upon request. Such records shall be retained on-site for a minimum of five years.

~~[45CSR§10-8.3.1. a.; 45CSR13: Permit R13-2334, 4.4.7.]~~

- 4.4.5. ~~For Heaters H-201, H-500S, H-600S, and H-701, the permittee shall determine total daily sulfur dioxide emissions from each of these heaters attributable to each fuel fired during twenty-four (24) hours period that Sulfur dioxide emissions attributable to the combustion of refinery fuel gas shall be determined using continuous hydrogen sulfide monitoring data collected in accordance with Condition 4.2.7. in conjunction with daily determination of the RFG heating value and density and accurate daily measurements of the volume of RFG fired in each heater. Said records shall be maintained in accordance with Condition 3.4.2. of this permit. The owner or operator of a fuel burning unit(s) or a combustion source(s) shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each unit in a manner specified 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§10-8.3.e.; 45CSR13: Permit R13-2334, 4.4.7, 8. CO-SIP-95-1 - Conditions V.4.A, and V.4.C. (SIPed)]~~

Boilers A and B, All Heaters (except H-101R, H-102R, H-500S, H-501R, H-441 and H-1101)

- 4.4.6. For any periods for which sulfur dioxide or oxides emissions data are not available ~~for demonstrating compliance with Condition 4.1.15., 4.1.16. and 4.1.5.b. of this permit,~~ the ~~permittee owner or operator of the affected facility~~ shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

~~[40 CFR §60.107(d); and 45CSR§16-4.1; 45CSR13: Permit R13-2334, 4.4.8, 14.]~~

- 4.4.7. The Company shall maintain records of the occurrence and duration of any start-up, shut-down or malfunction in the operation of sources subject to CO-SIP-95-1 (**Boilers A and B, All Heaters (except H-101R, H-102R, H-500S, H-501R, H-441 and H-1101)**), any malfunction of air pollution control equipment or any periods during which a continuous monitoring system or device is inoperative.

[CO-SIP-95-1 - Condition VI.4. (SIPed)]

Boilers A and B

- 4.4.8. ~~The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring devices, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR60 recorded in a permanent form suitable for inspection. The file shall be retained in accordance with Condition 3.4.21. of this permit, except as follows: To determine compliance with the emission limits set forth for Boiler A and Boiler B set forth in Section 4.1.14, the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the two boilers, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4 may be used to estimate monthly emissions of all pollutants except SO₂. The SO₂ monthly emissions shall be estimated using a blended fuel emission factor of 0.00577 lb SO₂/MMBtu for 20% refinery gas and 80% natural gas. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with this limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.3.A. (SIPed) and 45CSR§10-3.1.e.~~
[45CSR13: Permit R13-2334, 4.4.9., 45CSR§30-5.1.c., CO-SIP-95-1—Condition IV.3.A. (SIPed) and and 45CSR§10-3.1.e.]

- a. ~~Where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard using a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under 1st paragraph of this condition, the permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.~~
- b. ~~Where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under 1st paragraph of this condition, the permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Director and/or Administrator.~~

[45CSR16; 40 CFR §§60.7(f), (f)(1), (f)(2); 45CSR13: Permit R13-2334, 4.4.9.]

Boiler C

- 4.4.9. ~~The following requirements shall be used in determining compliance with NSPS Subpart KKKK NO_x limits and identifying excess emissions from CEMs data. To determine compliance with the emission limits for Boiler C, set forth in Section 4.1.17, the permittee shall keep monthly records of the amount of natural gas consumed within Boiler C and the hours of operation. This information along with appropriate emission factors from EPA's Compilation of Air Pollutant Emission Factors AP-42 Fifth Edition, Volume I, Supplement D: Stationary Point and Area Sources (AP-42), Chapter 1.4. may be used to estimate monthly emissions of all pollutants except NO_x. The emission factor for NO_x shall be 0.050 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.~~
[45CSR13: Permit R13-2334, 4.4.10.]

- a. All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).
- b. 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 and lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR Part 60. For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂, a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.
- c. Correction of measured NO_x concentrations to 15 percent O₂ is not allowed for the NO_x NSPS Subpart KKKK limit listed in Condition 4.1.4.a.i.
- d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in Subpart D of 40 CFR Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c) and in Condition 4.5.1.
- e. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
- f. Calculate the hourly average NO_x emission rates, in units of the emission standards under 40 CFR §60.4320, using the following equation for units complying with the output-based standard:

1. For Simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \quad \text{(Equation 1 of 40 CFR 60, Subpart KKKK)}$$

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/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

2. For combined-cycle operation: For complying with the NO_x output-based standard, the permittee shall use Equation 1 of 40 CFR 60, Subpart KKKK, except that the gross energy output (P) is calculated as the sum of the total electrical and thermal 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:

$$P = (Pe)_t + (Pe)_c + P_s + P_o \quad \text{(Equation 2 of 40 CFR 60 Subpart KKKK)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)_c = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)_s = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_s = \frac{Q \cdot H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Equation 3 of 40 CFR 60 Subpart KKKK})$$

Where:

P_s = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10⁶ = conversion from Btu/h to MW.

P_o = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

g. “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. The permittee shall determine excess emissions for each 30-day rolling average NO_x emission rate is greater than the Subpart KKKK Standard in Condition 4.1.4.a.i. of this permit.

h. 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, diluent gas (CO₂ or O₂) 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.

i. A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

[45CSR16; 40 CFR §60.4350, §§60.4380(b)(1), (b)(2), (c)(2); 45CSR13: Permit R13-2334, 4.4.14.]

- 4.4.10. To demonstrate compliance with the annual emission limits set forth set forth in Conditions 4.1.4.b. and 4.1.4.f., the permittee shall determine the monthly emissions and 12-month rolling total emissions from Emission Point TDB01 by no later than the 15th day of the following month. For periods that CEMs data is not valid, the permittee shall use the best information available and operational status of the combustion turbine (e.g., SoLoNO_x non-SoLoNO_x mode, startup event, shutdown event) and duct burner to determine NO_x emissions for the period. For periods equal to and less than one operating hour of missing or invalid CEM data, the permittee is allowed to use the average of NO_x emissions of the hour before and hour after the missing hour if the operating status of the combustion turbine and duct burner was the same for all periods.

Said records, which should include calculations in determining NO_x for periods of the missing or invalid CEM data, shall be maintained in accordance with Condition 3.4.1. of this permit.
[45CSR13: Permit R13-2334, 4.4.15.]

(1) — Except as provided under 40 C.F.R. §§60.48c(g)(2) and (g)(3), the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) — As an alternative to meeting the requirements of 40 C.F.R. §60.48c(g)(1), the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO₂ 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.

(3) — As an alternative to meeting the requirements 40 C.F.R. §60.48c(g)(1), 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 this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO₂ 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.

[40 C.F.R. §60.48c(g) and 45CSR§16-4.1]

4.4.11. All records required under 40 C.F.R. 60 Subpart Dc shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

[40 C.F.R. §60.48c(i) and 45CSR§16-4.1]

Heaters H-101R, H-102R, H-201, H-441, H-501R, H-701, H-500S and H-600S

4.4.12. To demonstrate compliance with energy input limits set forth in Conditions 4.1.4.h. and 4.1.4.i., each month the permittee shall determine the hourly amount of energy input into the combustion turbine and duct burner on a daily average based for each operating day by no later than the 15th day of the following month. Said records shall be maintained in accordance with Condition 3.4.1. of this permit.
[45CSR13: Permit R13-2334, 4.4.16.]

To determine compliance with the emission limits set forth for H-101R, H-102R, and H-501R set forth in Section 4.1.18., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within both heaters for H-101R and H-102R, and individually for H-501R. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4, may be used to estimate monthly emissions of all pollutants except NO_x and SO₂. SO₂ emission factors shall be based on the 1995 SO₂-SIP and heating value (HHV) of 1019 Btu/scf, which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.4. (SIPed) and 45CSR§10-3.1.e.

[45CSR13: Permit R13-2334, 4.4.11. (H-101R, H-102R, H-501R), CO-SIP-95-1 — IV.4. (SIPed); 45CSR§10-3.1.e.]

- 4.4.13. ~~Each month the permittee shall identify all periods that the combustion turbine was not operating in the SoLoNO_x™ mode and reason for not operating the combustion turbine in the SoLoNO_x™ mode by no later than the 15th of the following month. The permittee shall maintain records either on-site or off-site and be accessible to the Director or his/her duly authorized representative within seven (7) calendar days of the request of records of the recorded parameters used to determine the status for the SoLoNO_x™ mode. Said records shall be maintained in accordance with Condition 3.4.2. of this permit except as stated in this condition.~~

~~[45CSR13: Permit R13-2334, 4.4.17.]~~

~~To determine compliance with the emission limits for H-441 set forth in Section 4.1.19., the permittee shall keep monthly records of the amount of natural gas consumed in the heater. This information along with appropriate emission factors from EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4 may be used to estimate monthly emissions.~~

~~[45CSR13: Permit R13-2334, 4.4.12. (H-441)]~~

- 4.4.14. ~~To determine compliance with the emission limits set forth for H-201, H-500 Series, H-600 Series, and H-701 in Sections 4.1.19. and 4.1.22., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the four heaters, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4. may be used to estimate monthly emissions of all pollutants except SO₂. SO₂ emission factors shall be based on the 1995 SIP and heating value (HHV), which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4. Compliance with the SO₂ limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1, Condition IV.5. and 7. (SIPed) and 45CSR§10-3.1.e.~~

~~[45CSR13: Permit R13-2334, 4.4.13. (H-201, H-500S, H-600S, H-701), CO-SIP-95-1 – IV.5. and 7. (SIPed); 45CSR§10-3.1.e.]~~

Heater H-901

- 4.4.15. ~~The permittee shall keep monthly records of the amount of refinery fuel gas consumed by H-901. To determine compliance with NO_x, SO₂, VOC, and CO emissions limits for H-901, emission factors from manufacturer's specifications along with fuel gas consumption may be used. To determine compliance with the PM emission limits, AP-42 emission factors Table 1.4. 2 (1998) along with fuel gas consumption data may be used. Said records shall be maintained on-site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.15.]~~

- 4.4.16. ~~The permittee shall maintain continuous record for the H₂S concentration in the refinery fuel gas consumed by H-901. Said records shall be maintained on-site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~

~~[45CSR13: Permit R13-2334, 4.4.16.]~~

Heater H-1101

- 4.4.17. ~~The permittee shall keep monthly records of the amount of natural gas consumed by H-1101. To determine compliance with the NO_x, SO₂, and CO emission limits for H-1101, the permittee may use manufacturer's specifications and natural gas consumption. To determine compliance with the VOC and PM emission limit,~~

~~natural gas consumption data and AP 42 Table 1.4-2 (1998) using an average gas high heating value (HHV) of 1020 BTU/scf may be used. Said records shall be maintained on-site for a period of five (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.~~
~~[45CSR13: Permit R13-2334, 4.4.17.]~~

Heaters H-101R, H-102R, H-500S, and H-501R

4.4.14. ~~4.4.18.~~ The permittee shall maintain records in accordance with 40 CFR §60.108a:

- a. Each permittee subject to the emissions limitations in 40 CFR §60.102a shall comply with the notification and recordkeeping requirements in 40 CFR §60.7 and other requirements as specified in 40 CFR §60.108a which shall include Condition 4.5.2. of this permit
- c. The permittee shall maintain the following records:
 6. Records of discharges greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device subject to Condition 4.1.15 of this permit. The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:
 - i. A description of the discharge.
 - ii. The date and time the discharge was first identified and the duration of the discharge.
 - iii. The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices.
 - v. For each discharge greater than 500 lb SO₂ in excess of the applicable short-term emissions limit in 40 CFR §60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H₂S in the fuel gas or the measured concentration of SO₂ in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices.
 - vii. For each discharge greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device, the cumulative quantity of H₂S and SO₂ released into the atmosphere. For fuel gas combustion devices, assume 99-percent conversion of H₂S to SO₂.
 - viii. The steps that the owner or operator took to limit the emissions during the discharge.
 - ix. The root cause analysis and corrective action analysis conducted as required in 40 CFR §60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under 40 CFR §60.103a(e).
 - x. For any corrective action analysis for which corrective actions are required in 40 CFR §60.103a(e), a description of the corrective action(s) completed within the first 45 days

following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

Said records shall be maintained in accordance with Condition 3.4.2. of this permit.
[45CSR16, 40 CFR §§60.108a(a) and (c) (6), 45CSR13: R13-2334, 4.4.~~10, 18, and 4.4.11-4.5.5.~~]

Portable Boiler

~~4.4.15.~~ ~~4.4.19.~~ In order to demonstrate compliance with the requirements of 4.1.~~23~~ ~~31~~ and 4.2.~~10~~ ~~15~~, the permittee shall record the number of hours of operation of the Portable Boiler on a monthly basis.
[45CSR13: R13-2334, 4.4.~~12, 19~~]

~~4.4.16.~~ ~~4.4.20.~~ In order to demonstrate compliance with the requirements of 4.1.~~24~~ ~~32~~, the permittee shall record all the dates on which the Portable Boiler is brought on site and removed from the site.
[45CSR13: R13-2334, 4.4.~~13, 20~~]

4.5. Reporting Requirements

All Boilers, Heaters H-101R, H-102R, H-441, H-501R, H-701, H-500S, H-600S, H-901, H-1101

4.5.1. The ~~permittee owner or operator of a fuel burning unit(s) subject to 45CSR2~~ shall report to the Director any malfunction of ~~Boilers A, B, C, and the duct burner when in operation for the combustion turbine 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 Director:
 1. The excess opacity period does not exceed thirty (30) minutes within any 24-hour period; and
 2. Excess opacity does not exceed 40%.
- b. The ~~permittee owner or operator~~ shall report to the Director any malfunction resulting in excess particulate matter or excess opacity, not meeting the criteria set forth in 45CSR§2-9.3.~~1 a~~, by telephone, ~~telefax~~, or e-mail by the end of the next business day after becoming aware of such condition. The ~~permittee owner or operator~~ shall file a certified written report concerning the malfunction with the Director within thirty (30) days ~~in accordance with Condition 3.5.3.~~ 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 program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[45CSR§2-9.3.; 45CSR13: R13-2334, 4.5.1.]

Boilers A and B, Heaters H-101R, H-102R, H-501R, H-500S, H-600S, H-901

- 4.5.2. ~~For the boilers, process heaters, and duct burner subject to the H₂S standard in Conditions 4.1.15., 4.1.16., 4.1.15.; Boilers A and B to the NO_x standard in Condition 4.1.1.b.; and the Heater H-101R to the NO₂ standard in Condition 4.1.5.b., the permittee shall submit excess emissions and monitoring system performance report to the Director in accordance with Condition 3.5.3. for the six (6) month period of January 1 through June 30 and July 1 through December 31 by no later than 30th day following the end of each six (6) month period. The owner or operator shall submit a periodic exception report to the Director, in a manner specified by the Director. Such an exception report shall provide details of all excursions outside the range of measured emissions or monitored parameters established in an approved monitoring plan (see Appendix A) and shall include, but not be limited to, the time of the excursion, the magnitude of the excursion, the duration of the excursion, the cause of the excursion and the corrective action taken.~~

Such reports shall contain the following information:

- a. The information and in the format listed in Appendix B of this permit for each pollutant monitored.
- b. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
- c. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
- d. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- e. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- f. For units subject to Condition 4.1.15 and excess emissions occurred as defined in Condition 4.2.6.e., the permittee shall provide the additional information.
 1. The date that the exceedance occurred.
 2. An explanation of the exceedance.
 3. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and
 4. A description of the action taken, if any.

- 5. The information described in 40 CFR §60.108a(c)(6) for all discharges listed in 40 CFR §60.108a(c)(6)
- 6. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.
- g. For units subject to Condition 4.1.16 and excess emissions occurred as defined in Condition 4.2.6.f., the permittee shall identify those excess emissions in the report.
- h. For units subject to Condition 4.1.17 and excess emissions occurred as defined in Condition 4.2.6.g., the permittee shall identify those periods, which includes the duration of the excess emission, the magnitude of the excess emission in the report, and actions taken to resolve and/or minimize the magnitude of the excess emissions.
- i. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
- j. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Director or Administrator.
- k. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.

[45CSR§10-8.3.2, ~~b.~~; 45CSR16; 40 CFR §§60.7(c) and (d), §60.107(f), §60.108a(d); 45CSR13: Permit R13-2334, 4.5.2.]

Boilers A and B, Heaters H-201, H-441, H-701, H-500S, H-600S

- 4.5.3. **For Boilers A and B, H-201, H-441, H-701, H-500S, H-600S:** The Company shall submit an excess emissions and monitoring systems performance report to the Director for all sources for which the Company is required to maintain and operate a continuous monitoring system or monitoring device for sulfur dioxide or hydrogen sulfide on a calendar monthly basis. All such reports shall be submitted by the 30th day following the end of each calendar month and shall contain the results of all determinations showing excess emissions regardless of whether the determinations are made by continuous monitoring data or by other methods established by CO-SIP-95-1. Written reports of excess emissions shall include the following information:
- a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, the date and time at which the excess emissions started and ended for each occurrence of excess emissions and the process operating time during the reporting period.

- b. Specific identification of each period of excess emissions that occurred during start-ups, shut-downs and malfunctions of the affected facility. Each malfunction report filed with the Director in accordance with Section 4.5.4. shall be referenced by report number with the date of occurrence and date of report submission noted.
- c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired or adjusted, such information shall be stated in the report.

If the total duration of excess emissions during the reporting period is less than one percent (1%) of the total operating time for the reporting period, and downtime for the continuous monitoring system for the reporting period is less than five percent (5%) of the total operating time for the reporting period, only the summary report form listed as Figure 1 in 40 CFR Part 60.7(d) shall be submitted, and the excess emission report described above need not be submitted unless requested by the Director. If the total duration of excess emissions for the reporting period is one percent (1%) or greater of the total operating time for the reporting period, or the total continuous system downtime for the reporting period is five percent (5%) or greater of the total operating time for the reporting period, the summary report from and the excess emission report described above shall both be submitted to the Director.

[CO-SIP-95-1 - Condition VI.3. (SIPed)]

- 4.5.4. For Boilers A and B, H-201, H-441, H-701, H-500S, H-600S: The Company shall report to the Director, by telephone or telefax, any malfunction of such source or its air pollution control equipment which results in any excess sulfur dioxide emission rate or concentration within twenty-four (24) hours of becoming aware of such condition. The Company shall file a written report concerning the malfunction with the Director within ten (10) days, providing the following information:

- a. A detailed explanation of the factors involved or causes of the malfunction.
- b. The date and time of duration (with starting and ending times) of the period of excess emissions.
- c. An estimate of the mass of excess emissions discharged during the malfunction period.
- d. The maximum emission rate or concentration measured or otherwise determined during the malfunction in units of the applicable emissions standard.
- e. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction.
- f. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation.

[CO-SIP-95-1 - Condition VI.7. (SIPed)]

Boiler-C

- ~~4.5.5. The permittee is responsible for submitting notification of the date of construction or reconstruction, anticipated startup, and actual startup and complying with 40 CFR §60.40c, 40 CFR §60.48c, and 40 CFR~~

~~§60.8. The permittee has complied with this requirement by submitting notification. Renotification will be required if modifications are made.~~

~~[40 CFR §60.48c and 45CSR§16 4.1.; 45CSR13: R13-2334, 4.5.3.]~~

~~4.5.5.~~ 4.5.6 The reporting period for the reports required under this subpart is each six-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.

~~[40 C.F.R. §60.48c(j) and 45CSR§16-4.1]~~

~~Heater H-901~~

~~4.5.7. For any periods for which sulfur dioxide or oxides emissions data are not available for H-901, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.~~

~~[40 CFR §60.107(d) and 45CSR§16 4.1; 45CSR13: Permit R13-2334, 4.5.4.]~~

~~Heaters H-101R, H-102R, H-500S, and H-501R~~

~~4.5.8. Each permittee subject to the emissions limitations in 40 CFR § 60.102a shall comply with the reporting requirements in 40 CFR § 60.7 and other requirements as specified in 40 CFR § 60.108a.~~

~~[45CSR16, 40 CFR §§ 60.108a (a), 45CSR13: R13-2334, 4.5.5.]~~

~~4.5.9. Each permittee subject to 40 CFR Part 60 Subpart Ja shall submit an excess emissions report for all periods of excess emissions according to the requirements of 40 CFR §60.7(c) except that the report shall contain the information specified in 40 CFR §60.108a(d)(1) through (7).~~

~~1. The date that the exceedance occurred;~~

~~2. An explanation of the exceedance;~~

~~3. Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and~~

~~4. A description of the action taken, if any;~~

~~5. The information described in 40 CFR § 60.108a (c) (6) for all discharges listed in paragraph (c) (6).~~

~~6. For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.~~

~~7. A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.~~

~~[45CSR16, 40 CFR § 60.108a (d), 45CSR13, R13-2334, 4.5.5.]~~

4.5.6. The permittee shall prepare and submit an excess emission report on a semi-annual basis to the Director and Administrator for NO_x and SO₂ emissions from TBD01 as required by Subpart KKKK of 40 CFR 60. The initial compliance period is from initial startup up of combustion turbine (TDB01) to either December 31 or June 30 whichever date comes first. Subsequent reporting periods shall be every six months thereafter (e.g., January 1 to June 30, July 1 to December 31). Reports must be submitted no later than the 30th day following the end of the reporting period. Each report must contain the following information that occurred within the respective reporting period. Each report shall be submitted in accordance with Condition 3.5.3.

- a. Excess Emissions of sulfur dioxide emissions shall mean the total sulfur content of the fuel being combusted in the turbine exceeds the limit specified in 40 CFR §60.4330 (See Condition 4.1.4.a.ii. SO₂ limit for Subpart KKKK). An SO₂ excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. If electing to utilize the alternative monitor requirements for daily average H₂S concentration readings of the refinery fuel gas from the H₂S monitor as required in Condition 4.2.2.e., the daily average concentration (converted from H₂S into the form of the SO₂ emission standard stated in Condition 4.1.4.a.ii) shall be used to determine excess SO₂ emissions. An SO₂ excess emission occurs each unit operating hour included in any daily average concentration which exceeds the applicable limit and ending on the date and hour that a subsequent daily average demonstrates compliance with the SO₂ emission standard.
- b. Excess Emissions of NO_x means a specified averaging period (30-day rolling) over which the NO_x emissions are higher than the applicable emission limit in 40 CFR 60.4320 (See Condition 4.1.4.a.i. NO_x limit for Subpart KKKK).
- c. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you 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 start-up, shutdown, and malfunction.
- d. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each period of excess emissions. The process operating time during the reporting period.
- e. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted.
- f. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
- g. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
- h. The summary report form shall contain the information and be in the format shown in Appendix B of the permit unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

- i. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted, and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Administrator.
- j. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.

[45CSR16; 40 CFR §§60.7(c) and (d), §60.4375(a), §60.4380(b), §60.4385, §60.4395, 45CSR13: Permit R13-2334, 4.5.3.]

- 4.5.7. The permittee shall submit to the Director within 60 days of completion of CEMS performance evaluation for TDB01 two copies of the performance evaluation report to satisfy Part 60 notification requirements for certifying the CEMS.

[45CSR16; 40 CFR §§60.13(c) and (c)(2); 45CSR13: Permit R13-2334, 4.5.4.]

- 4.5.8. The permittee shall notify the Director within thirty (30) calendar days of switching to a different sampling schedule as allowed or required in Condition 4.2.1. of this permit. Such notification shall include the date of the actual switch and reason to include justification for switching the sampling schedule.

[45CSR13: Permit R13-2334, 4.5.5.]

- 4.5.9. The permittee shall submit a notification of the actual date of initial startup of TDB01 within 15 days after such date, to the Director and Administrator, in accordance with Condition 3.5.3. of this permit.

[45CSR16; 40 CFR §60.7(a)(3); 45CSR13: Permit R13-2334, 4.5.6.]

- 4.5.10. The permittee shall submit a notification acknowledging the provisions of Condition 4.1.3. (See 4.120. through 4.1.25. of this permit) of permit R13-2334 are no longer effective within 15 calendar days of the end date for Condition 4.1.25. of this permit (180 days after the actual initial startup date of TDB01) to the Director in accordance with Condition 3.5.3. of this permit.

[45CSR13: Permit R13-2334, 4.5.7.]

- 4.5.11. The permittee shall submit a notification for any exceedance of the annual emission limits in Condition 4.1.4. of this permit to the Director in accordance with Condition 3.5.3.

[45CSR13: Permit R13-2334, 4.5.8.]

4.6. Compliance Plan

- 4.6.1. None.

5.0 F1, T Load, OXIDIZER, MLD, MLDOX, and NH3OX Requirements

5.1. Limitations and Standards

- 5.1.1. The Main Flare [F1/00A-01], the Sour Gas Flare [F2/00A-03], the Truck Loading Thermal Oxidizer [OXIDIZER/00A-02], the Marine Loading Thermal Oxidizer [MLDOX/00A-04], and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX], are subject to the requirements of 45CSR6 including but 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 the use of the following formula:

$$\text{Emissions(lb/hr)} = F \times \text{Incinerator Capacity (tons/hr)}$$

where the factor, F, is as indicated in the table below:

Incinerator Capacity	F Factor
Less than 15,000 lbs/hr	5.43
15,000 lbs/hr or greater	2.72

Emission ID	Calculation	Limit (lbs/hr)
F1 [00A-01] and F2 [00A-03]	$2.72 \times 395,000 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	537.2
OXIDIZER [00A-02]	$5.43 \times 64.8 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	0.176
MLDOX [00A-04]	$5.43 \times 4600 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	12.5
NH3OX [00A-05]	$5.43 \times 416.08 \text{ lbs/hr} \times 1 \text{ ton}/2000 \text{ lbs}$	1.13

- 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.
- c. Incinerators, including all associated equipment and grounds, shall be designed, operated and maintained so as to prevent the emission of objectionable odors.

[45CSR§§6-4.1., 4.3, 4.6.; 45CSR13: Permit R13-2334, 5.1.6.]

- 5.1.2. No person shall cause, suffer, allow, or permit the emission into open air from any source operation an in-stack sulfur dioxide concentration exceeding 2000 ppm by volume from existing source operations. Note: “In-stack” concentration as interpreted for a flare means the exhaust concentration after combustion.

[45CSR§10-4.1.; 45CSR13: Permit R13-2334 - 5.1.7.]

- 5.1.3. a. For the Main Flare F1, the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H₂S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. 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 limit.
[40 CFR §60.103a(h), 45CSR§16-4.1; 45CSR13: Permit R13-2334, 5.1.9., and CO-SIP-95-1 - Condition IV.9. (SIPed) (00A-01)]
- b. For the Sour Gas Flare [F2], the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf) determined hourly on a 3-hour

rolling average basis. 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 paragraph. **[40 CFR §60.104(a)(1), 45CSR§16-4.1; 45CSR13: Permit R13-2334, 5.1.10., and CO-SIP-95-1 - Condition IV.9. (SIPed) (00A-03)]**

Compliance with these limits shall demonstrate compliance with the 50 gr/100dscf limit from CO-SIP-95-1, Condition IV.9.

- 5.1.4. During Truck Loading of gasoline, VOC emissions shall be controlled by the Loading Rack Thermal Oxidizer.
[45CSR13: Permit R13-2334, 5.1.3. (00A-02)]
- 5.1.5. Gas generated at the sour water stripper shall continue to be processed through the fuel gas treatment system and the Company shall exercise good operating and maintenance practices to maximize the utilization of the fuel gas treatment system to remove sulfur compounds from the sour gas stream and further provided, that in no event shall the emissions of sulfur dioxide from the sour gas flare exceed 18 lbs./hr.
[CO-SIP-95-1 - Condition IV.9. (SIPed)]
- 5.1.6. The permittee shall implement a program to investigate the cause of Acid Gas Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Acid Gas Flaring Incidents, and minimize Acid Gas Flaring Incidents. The permittee shall evaluate whether Acid Gas Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forth the Root Cause and all contributing causes of the Acid Gas Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Acid Gas Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.
- a. "Acid Gas Flaring Incident" means the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the AG Flaring Incident. "Acid Gas" means any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of amine solution.
- b. "Acid Gas Flaring" means the combustion of Acid Gas and/or Sour Water Stripper Gas in an Acid Gas Flaring Device. "Acid Gas Flaring Device" shall mean any device at EWVI that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The Acid Gas Flaring Device currently in service at EWVI is F2 [00A-03].
- c. "Sour Water Stripper Gas" shall mean the gas produced by the process of stripping refinery sour water.
- d. "Root Cause" means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.

- e. "Malfunction" means, as specified in 40 CFR Part §60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR13: Permit R13-2334, 5.1.16.]

- 5.1.7. In response to any Acid Gas or Hydrocarbon Flaring Incident from the Sour Gas Flare [F2], the permittee shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that Acid Gas or Hydrocarbon Flaring Incident.

[45CSR13: Permit R13-2334, 5.1.17.]

- 5.1.8. The permittee shall implement a program to investigate the cause of Hydrocarbon Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Hydrocarbon Flaring Incidents, and minimize Hydrocarbon Flaring Incidents. The permittee shall evaluate whether Hydrocarbon Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forth the Root Cause and all contributing causes of the Hydrocarbon Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Hydrocarbon Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.

- a. "Hydrocarbon Flaring Incident" means the continuous or intermittent Hydrocarbon Flaring, except for Acid Gas and/or Sour Water Stripper Gas, at a Hydrocarbon Flaring Device that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five-hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one Hydrocarbon Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the Hydrocarbon Flaring Incident.
- b. "Hydrocarbon Flaring" means the combustion of refinery-generated gases, except for Acid Gas and/or Sour Water Stripper Gas in a Hydrocarbon Flaring Device.
- c. "Hydrocarbon Flaring Device" means a flare device used to control (through combustion) any excess volume of a refinery generated gas other than Acid Gas and/or Sour Water Stripper Gas.
- d. "Root Cause" means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.
- e. "Malfunction" means, as specified in 40 CFR Part 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[45CSR13: Permit R13-2334, 5.1.18]

5.1.9. Emissions shall not exceed those listed below. Annual emission limits are based on a 12-month rolling basis.

Pollutant	Emission Point ID									
	F1 (pilot light)		F2 (pilot light)		TLOAD & OXIDIZER		MLD & MLDOX		NH3OX	
	TPM*	TPY	TPM*	TPY	TPM*	TPY	TPM*	TPY	TPM*	TPY
CO	0.007	0.074	0.013	0.129	0.21	2.12	0.27	2.67	0.80	7.96
NO _x	0.009	0.088	0.015	0.153	0.04	0.39	0.05	0.49	0.05	0.50
PM _{2.5}	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
PM ₁₀	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
PM	0.001	0.007	0.001	0.012	0.01	0.04	0.01	0.05	0.02	0.22
SO ₂					0.13	1.26	0.19	1.85	0.01	0.02
VOC	0.001	0.005	0.001	0.008	1.82	18.17	1.22	12.24	0.10	1.00
Total HAPs					0.32	3.22	0.13	1.3		
Benzene					0.03	0.32	0.01	0.08		

Pollutant	Emission Point ID			
	Railcar Unloading		Air Separator / Recovery Drum	
	TPM*	TPY	TPM*	TPY
VOC	1.46	17.55	0.36	4.35
Hexane	0.04	0.51	0.01	0.08
Benzene	0.04	0.49	0.01	0.08
Isooctane	0.01	0.04	0.01	0.01
Toluene	0.02	0.26	0.01	0.04
Ethylbenzene	0.01	0.04	0.01	0.01
Xylene	0.01	0.11	0.01	0.02
Total HAPs	0.12	1.45	0.02	0.23

*TPM = Tons per month

[45CSR13 - Permit R13-2334 - 5.1.1.]

5.1.10. The permittee shall not exceed the annual limits in the table below that correspond to the emission limits established in requirement 5.1.9. Annual quantities are based on a 12-month rolling basis.

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Marine Loading	Gasoline	62,031
	Light Crude Oil (including oil with a vapor pressure up to 11.0 psia)	306,600
	Diesel	37,065
	Kerosene	46,000
	Lube Oil/ Heavy Products	30,660
Truck Loading	Diesel	134,904
	Gasoline	134,904
	No. 6 Fuel Oil	13,650
	Kerosene	15,330
	Lube Oil/ Heavy Products	136,920

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Railcar Unloading	Waxy Crude	38,325
	Total Crude (Waxy & Penn)	76,650

[45CSR13 - Permit R13-2334 - 5.1.2.]

- 5.1.11. The Main Flare [F1] is an affected facility as that term is used in 40 CFR Part 60 and is subject to the requirements of 40 CFR Part 60, Subparts A and Ja . The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d) and with the applicable work practice standards of NSPS, Subpart Ja.

[45CSR16; 40 CFR §60.103a; 45CSR13: Permit R13-2334 - 5.1.13. and 5.1.15]

- 5.1.12. The Sour Gas Flare [F2] is an affected facility as that term is used in 40 CFR Part 60 and is subject to the requirements of 40 CFR Part 60, Subparts A and J. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR §60.11(d).

[45CSR13: Permit R13-2334, 5.1.14.]

- 5.1.13. Marine Loading.

- a. During marine loading of gasoline and light crude oil, VOC emissions shall be controlled by the Marine Barge Loading Thermal Oxidizer [MLDOX/ 00A-04]. MLDOX shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 98% for VOCs.

- b. All vessels loaded from the Marine Loading Dock (MLD) shall be submerged filled.

[45CSR13: Permit R13-2334, 5.1.4.]

- 5.1.14. Emissions from the Ammonia Destruction Unit (ADU) shall be routed to the ADU Thermal Oxidizer [NH3OX/00A-05] at all times that the ADU is in operation. The thermal oxidizer [NH3OX] shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 99.9% for VOCs.

[45CSR13: Permit R13-2334, 5.1.5.]

- 5.1.15. No refined products (e.g. gasoline, naphtha, ethanol, diesel) shall be received via rail.

[45CSR13: Permit R13-2334, 5.1.8.]

- 5.1.16. Existing sources with emissions less than 10 and 25 tons must meet the submerged fill standards of 46 CFR 153.282.

- a. The discharge point of a cargo tank filling line must be no higher above the bottom of the cargo tank or sump than 10 cm (approx. 4 in.) or the radius of the filling line, whichever is greater.

[46 C.F.R. §153.282]

[40 C.F.R. §63.560(a)(4); 45CSR34] (MLD and MLDOX)

- 5.1.17. Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.

[40 C.F.R. §60.502(a); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.18. The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in 40 C.F.R. §60.502(c).

[40 C.F.R. §60.502(b); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.19. Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:

- a. The owner or operator shall obtain the vapor tightness documentation described in 40 C.F.R. §60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.
- b. The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.
- c.
 - i. The owner or operator shall cross-check each tank identification number obtained in 40 C.F.R. §60.502(e)(2) with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded, unless either of the following conditions is maintained:
 - A. If less than an average of one gasoline tank truck per month over the last 26 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed each quarter; or
 - B. If less than an average of one gasoline tank truck per month over the last 52 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed semiannually.
 - ii. If either the quarterly or semiannual cross-check provided in 40 C.F.R. §§60.502(e)(3)(i)(A) through (B) reveals that these conditions were not maintained, the source must return to biweekly monitoring until such time as these conditions are again met.
- d. The terminal owner or operator shall notify the owner or operator of each non-vapor-tight gasoline tank truck loaded at the affected facility within 1 week of the documentation cross-check in 40 C.F.R. §60.502(e)(3).
- e. The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.
- f. Alternate procedures to those described in 40 C.F.R. §60.502(e)(1) through (5) for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.

[40 C.F.R. §60.502(e); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.20. The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

[40 C.F.R. §60.502(f); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.21. The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

[40 C.F.R. §60.502(g); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.22. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in §60.503(d).

[40 C.F.R. §60.502(h); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.23. Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

[40 C.F.R. §60.502(j); 45CSR16] (T Load) (During gasoline loading only)

- 5.1.24. Each owner or operator of an affected source under this subpart must comply with the requirements of 40 C.F.R. §§63.11085(a) and (b).

(a) You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. 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.

(b) You must keep applicable records and submit reports as specified in 40 C.F.R. §63.11094(g) and 40 C.F.R. §63.11095(d).

[40 C.F.R. §63.11085; 45CSR34] (T Load) (During gasoline loading only)

- 5.1.25. The permittee must meet each emission limit and management practice in Table 2 to 40 C.F.R. 63 Subpart BBBBBB that applies to you.

If you own or operate ...	Then you must ...
1. A bulk gasoline terminal loading rack(s) with a gasoline throughput (total of all racks) of 250,000 gallons per day, or greater. Gallons per day is calculated by summing the current day's throughput, plus the throughput for the previous 364 days, and then dividing that sum by 365	(a) Equip your loading rack(s) with a vapor collection system designed to collect the TOC vapors displaced from cargo tanks during product loading; and
	(b) Reduce emissions of TOC to less than or equal to 80 mg/l of gasoline loaded into gasoline cargo tanks at the loading rack; and
	(c) Design and operate the vapor collection system to prevent any TOC vapors collected at one loading rack or lane from passing through another loading rack or lane to the atmosphere; and
	(d) Limit the loading of gasoline into gasoline cargo tanks that are vapor tight using the procedures specified in §60.502(e) through (j) of this chapter. For the purposes of this section, the term "tank truck" as used in

	§60.502(e) through (j) of this chapter means “cargo tank” as defined in §63.11100.

[40 C.F.R. §63.11088(a); Table 2 to 40 C.F.R 63 Subpart BBBB, 45CSR34] (T Load) (During gasoline loading only)

5.1.26. Requirements for equipment leak inspections at a bulk gasoline terminal, bulk plant, pipeline breakout station, or pipeline pumping station.

- (a) Each owner or operator of a bulk gasoline terminal, bulk plant, pipeline breakout station, or pipeline pumping station subject to the provisions of this subpart shall perform a monthly leak inspection of all equipment in gasoline service, as defined in 40 C.F.R. §63.11100. For this inspection, detection methods incorporating sight, sound, and smell are acceptable.
- (b) A log book shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log book shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.
- (c) Each detection of a liquid or vapor leak shall be recorded in the log book. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in 40 C.F.R. §63.11089(d) of this section.
- (d) Delay of repair of leaking equipment will be allowed if the repair is not feasible within 15 days. The owner or operator shall provide in the semiannual report specified in 40 C.F.R. §63.11095(b), the reason(s) why the repair was not feasible and the date each repair was completed.
- (e) You must comply with the requirements of this subpart by the applicable dates specified in 40 C.F.R. §63.11083.
- (f) You must submit the applicable notifications as required under 40 C.F.R. §63.11093.
- (g) You must keep records and submit reports as specified in 40 C.F.R. §§63.11094 and 63.11095.

[40 C.F.R. §63.11089; 45CSR34] (T Load) (During gasoline loading only)

5.2. Monitoring Requirements

5.2.1. The permittee shall monitor the PM emissions by conducting visible emissions checks in accordance with Section 4.2.1. of this permit.

[45CSR13 - R13-2334 - 5.2.1.]

5.2.2. To determine compliance with the emission rate limits set forth in Section 5.1.9., the permittee shall monitor hours of operation for pilot and non-pilot conditions of the Main Flare [F1] and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX]. Compliance with yearly limits shall be based on a 12-month rolling basis.

[45CSR13 - Permit R13-2334 - 5.2.2.]

5.2.3. To determine compliance with the annual emission rate limits set forth in Section 5.1.9. for the OXIDIZER and MLDOX, the permittee may estimate emissions using the monthly loading records, along with the

appropriate emission factors for loading losses from AP-42, Chapter 5.2 (7/08). Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13 - Permit R13-2334 - 5.2.3.]

- 5.2.4. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.13 for MLDOX, OXIDIZER, and NH3OX.

[45CSR16, 40 CFR §60.13, 45CSR13: R13-2334, 5.2.4]

- 5.2.5. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.107a for F1:

The owner or operator of a flare that is subject to the H₂S concentration requirement in Section 5.1.3.a. shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases before being burned in any fuel gas combustion device or flare.

- i. The owner or operator shall install, operate and maintain each H₂S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H₂S.
- ii. The owner or operator shall conduct performance evaluations for each H₂S monitor according to the requirements of 40 CFR §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.
- iii. The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H₂S monitor.
- iv. Flares 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 fuel gas combustion devices or flares.
- v. The owner or operator of a flare subject to 40 CFR 60.103(c) through (e) may use the instrument required in 40 CFR §60.107a(e)(1) to demonstrate compliance with the H₂S concentration requirement in 40 CFR §60.103a(h) if the owner or operator complies with the requirements of 40 CFR §§60.107a(e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in 40 CFR §60.107a(e)(1) is used to demonstrate compliance with the H₂S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in 40 CFR §60.103a(h).
- vi. The owner or operator of modified flare that meets all three criteria in paragraphs A. through C. below shall comply with the requirements of Section 5.2.5.i. through v. no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to 40 CFR §60.13(i) until the flare is in compliance with requirements of Section 5.2.5.i. through v.
 - A. The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under §60.100a.
 - B. The owner or operator had an approved alternative monitoring plan or plans pursuant to §60.13(i) for all fuel gases combusted in the flare.

- C. The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H₂S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

[45CSR16, 40 CFR §60.107a(a)(2), 45CSR13: Permit R13-2334, 5.2.5.]

- 5.2.6. In order to determine compliance with the railcar unloading throughput of condition 5.1.10, the permittee shall monitor and record the amount and type of crude oil unloaded from railcars on a monthly basis.

[45CSR13: Permit R13-2334, 5.2.6.]

- 5.2.7. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) while gasoline vapors are displaced to the vapor processor systems, as specified in 40 C.F.R. §63.11092(b)(1) through (5). For each facility conducting a performance test under paragraph 40 C.F.R. §63.11092(a)(1), and for each facility utilizing the provisions of 40 C.F.R. §63.11092(a)(2) or (a)(3), the CMS must be installed by January 10, 2011.

- (5) If you have chosen to comply with the performance testing alternatives provided under 40 C.F.R. §63.11092(a)(2) or (a)(3), the monitored operating parameter value may be determined according to the provisions in paragraph 40 C.F.R. §63.11092(b)(5)(i) or (b)(5)(ii).

- (i) Monitor an operating parameter that has been approved by the Administrator and is specified in your facility's current enforceable operating permit. At the time that the Administrator requires a new performance test, you must determine the monitored operating parameter value according to the requirements specified in 40 C.F.R. §63.11092(b).
- (ii) Determine an operating parameter value based on engineering assessment and the manufacturer's recommendation and submit the information specified in paragraph 40 C.F.R. §63.11092(b)(4) for approval by the Administrator. At the time that the Administrator requires a new performance test, you must determine the monitored operating parameter value according to the requirements specified in 40 C.F.R. §63.11092(b) of this section.

Note: In accordance with 40 CFR §63.11092(a)(2) and §63.11092(b)(5)(i), the OXIDIZER is equipped with a monitoring system to measure and record the temperature during gasoline truck loading events. The OXIDIZER temperature must achieve 1,000 °F during each loading event.

[40 C.F.R. §63.11092(b)(5);45CSR34] (T Load and OXIDIZER)

- 5.2.8. Each owner or operator of a bulk gasoline terminal subject to the provisions of 40 C.F.R. 63 Subpart BBBBBB shall comply with the requirements in 40 C.F.R. §63.11092(d)(1) through (4).

- (1) Operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the operating parameter value for the parameters described in 40 C.F.R. §63.11092(b)(1).
- (2) In cases where an alternative parameter pursuant to 40 C.F.R. §63.11092(b)(1)(iv) or 40 C.F.R. §63.11092 (b)(5)(i) is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value.

- (3) Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as appropriate, shall constitute a violation of the emission standard in 40 C.F.R. §63.11088(a), except as specified in 40 C.F.R. §63.11092(d)(4).
- (4) For the monitoring and inspection, as required under 40 C.F.R. §§63.11092(b)(1)(i)(B)(2) and (b)(1)(iii)(B)(2), malfunctions that are discovered shall not constitute a violation of the emission standard in 40 C.F.R. §63.11088(a) if corrective actions as described in the monitoring and inspection plan are followed. The owner or operator must:
 - (i) Initiate corrective action to determine the cause of the problem within 1 hour;
 - (ii) Initiate corrective action to fix the problem within 24 hours;
 - (iii) Complete all corrective actions needed to fix the problem as soon as practicable consistent with good air pollution control practices for minimizing emissions;
 - (iv) Minimize periods of start-up, shutdown, or malfunction; and
 - (v) Take any necessary corrective actions to restore normal operation and prevent the recurrence of the cause of the problem.

[40 C.F.R. §63.11092(d);45CSR34] (T Load and OXIDIZER)

- 5.2.9. When loading barges with gasoline or crude, the MLDOX shall be operated above the minimum temperature established during the performance test demonstrating the device achieves a minimum control efficiency of 98% for VOCs. For naphtha loading, the minimum operating temperature is 899 °F. For light crude loading, the minimum operating temperature is 1346 °F. The MLDOX shall be equipped with two (2) thermocouples with the second thermocouple serving as backup. The thermocouples shall have an accuracy/precision of at least $\pm 0.75\%$. The MLDOX temperature shall be continuously monitored and recorded using an electronic monitoring system. Continuous means at least one data point is recorded in each quadrant of the hour with a 1-hour block averaging period. MLDOX startup/shutdown periods are excluded from averaging. An excursion shall be defined as a temperature below the minimum operating temperature. Excursions trigger a system inspection and corrective action.

Monitoring equipment shall be installed and verified according to the manufacturer's specifications.

[45CSR§30-5.1.c; 40 C.F.R. 64.6(c)] (MLDOX)

- 5.2.10. When the Ammonia Destruction Unit (ADU) is in operation, the NH3OX shall be operated above the minimum temperature established during the performance test demonstrating the device achieves a minimum control efficiency of 99.9% for VOCs. The minimum operating temperature is 1630 °F. The NH3OX shall be equipped with two (2) thermocouples with the second thermocouple serving as backup. The thermocouples shall have an accuracy/precision of at least $\pm 0.75\%$. The NH3OX temperature shall be continuously monitored and recorded using an electronic monitoring system. Continuous means at least one data point is recorded in each quadrant of the hour with a 3-hour block averaging period. ADU/NH3DOX startup/shutdown periods are excluded from averaging. An excursion shall be defined as a temperature below the minimum operating temperature. Excursions trigger a system inspection and corrective action.

Monitoring equipment shall be installed and verified according to the manufacturer's specifications.

[45CSR§30-5.1.c; 40 C.F.R. 64.6(c)] (NH3OX)

- 5.2.11. **Commencement of operation.** The owner or operator shall conduct the monitoring required under this part upon issuance of a part 70 or 71 permit that includes such monitoring, or by such later date specified in the permit pursuant to §64.6(d).
[45CSR§30-5.1.c; 40 C.F.R. §64.7(a)] (MLDOX and NH3OX)
- 5.2.12. **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 C.F.R. §64.7(b)] (MLDOX and NH3OX)
- 5.2.13. **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 this part, 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 C.F.R. §64.7(c)] (MLDOX and NH3OX)
- 5.2.14. **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 C.F.R. §64.7(d)] (MLDOX and NH3OX)
- 5.2.15. **Documentation of need for improved monitoring.** After approval of monitoring under this part, 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 C.F.R. §64.7(e)] (MLDOX and NH3OX)

5.2.16. **Quality improvement plan (QIP) requirements.**

- a. Based on the results of a determination made under §64.7(d)(2), the Administrator or the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with §64.6(c)(3), the part 70 or 71 permit may specify an appropriate threshold, such as an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, for requiring the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.
- b. Elements of a QIP:
 1. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.
 2. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:
 - i. Improved preventive maintenance practices.
 - ii. Process operation changes.
 - iii. Appropriate improvements to control methods.
 - iv. Other steps appropriate to correct control performance.
 - v. More frequent or improved monitoring (only in conjunction with one or more steps under paragraphs (b)(2)(i) through (iv) of this section).
- c. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.
- d. Following implementation of a QIP, upon any subsequent determination pursuant to §64.7(d)(2) the Administrator or the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:
 1. Failed to address the cause of the control device performance problems; or
 2. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.
- e. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

[45CSR§30-5.1.c; 40 C.F.R. §64.8] (MLDOX and NH3OX)

5.3. Testing Requirements

- 5.3.1. The hydrogen sulfide concentrations of the sour gas stream used to determine daily compliance with Section 5.1.3. shall be determined on days when the fuel gas treatment system is not operating by running 2-hour samples of the hydrogen sulfide content of the water entering and exiting the sour water stripper unit. At least three (3) 2-hour samples shall be taken during each 24-hour period at approximately 8-hour intervals.

[CO-SIP-95-1 - Condition V.9. (SIPed)]

- 5.3.2. The permittee shall conduct an initial performance test of MLDOX to demonstrate compliance with the control efficiency provided in the Emissions Unit Table (minimum of 98%), Section 1.1, and shall establish operating parameters in accordance with the most recent performance test.

[45CSR13: Permit R13-2334, 5.3.1. (00A-04)]

- 5.3.3. The permittee shall meet all applicable performance tests requirements of 40 CFR §60.8 for MLDOX, OXIDIZER, and NH3OX.

[45CSR16, 40 CFR §60.8, 45CSR13: R13-2334, 5.3.2]

- 5.3.4. The permittee shall calculate an annual estimate of HAP emissions from gasoline and light crude oil from marine tank vessel loading operations. Emission estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source.

The recordkeeping requirements of 40 CFR §63.567(j)(4) and the emission estimation requirements of 40 CFR §63.565(l) apply to existing sources with emissions less than 10 and 25 tons.

[45CSR34, 40 CFR §§63.560(a)(3) and 63.565(l), 45CSR13: R13-2334, 5.3.4]

- 5.3.5. Immediately before the performance test required to determine compliance with 40 C.F.R. §60.502 (b), (c), and (h), the owner or operator shall use Method 21 to monitor for leakage of vapor all potential sources in the terminal's vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 10,000 ppm (as methane) or greater before conducting the performance test.

[40 C.F.R. §60.503(b); 45CSR16] (T Load)

- 5.3.6. The owner or operator shall determine compliance with the standards in §60.502 (b) and (c) as follows:

1. The performance test shall be 6 hours long during which at least 300,000 liters of gasoline is loaded. If this is not possible, the test may be continued the same day until 300,000 liters of gasoline is loaded or the test may be resumed the next day with another complete 6-hour period. In the latter case, the 300,000-liter criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.
2. If the vapor processing system is intermittent in operation, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.
3. The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K \sum_{i=1}^n (V_{est} C_{ei}) / L 10^6$$

where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{est} = volume of air-vapor mixture exhausted at each interval “i”, scm.

C_{ei} = concentration of total organic compounds at each interval “i”, ppm.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

i = emission testing interval of 5 minutes.

K = density of calibration gas, 1.83×10^6 for propane and 2.41×10^6 for butane, mg/scm.

4. The performance test shall be conducted in intervals of 5 minutes. For each interval “i”, readings from each measurement shall be recorded, and the volume exhausted (V_{est}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.
5. The following methods shall be used to determine the volume (V_{est}) air-vapor mixture exhausted at each interval:
 - i. Method 2B shall be used for combustion vapor processing systems.
 - ii. Method 2A shall be used for all other vapor processing systems.
6. Method 25A or 25B shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. The calibration gas shall be either propane or butane. The owner or operator may exclude the methane and ethane content in the exhaust vent by any method (e.g., Method 18) approved by the Administrator.
7. To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.

[40 C.F.R. §60.503(c); 45CSR16] (T Load)

5.3.7. The owner or operator shall determine compliance with the standard in §60.502(h) as follows:

1. A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ± 2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.

2. During the performance test, the pressure shall be recorded every 5 minutes while a gasoline truck is being loaded; the highest instantaneous pressure that occurs during each loading shall also be recorded. Every loading position must be tested at least once during the performance test.

[40 C.F.R. §60.503(d); 45CSR16] (T Load)

- 5.3.8. The MLDOX and NH3OX thermocouples shall be inspected no less than once per year to verify accuracy according to the manufacturer's recommendations.
[45CSR§30-5.1.c; 40 C.F.R. §64.6(c)] (MLDOX and NH3OX)

5.4. Recordkeeping Requirements

- 5.4.1. To determine compliance with the loading emission limits set forth in Section 5.1.9., the permittee shall keep a monthly record of the volume and type of each product/product type loaded at each truck loading station and marine barge loading station and whether or not the VOC emissions were controlled using the control devices [OXIDIZER or MLDOX]. AP-42 emission factors for flares and transportation and marketing of petroleum liquids (Chapter 5.2, 1/95) or test data may be used to estimate emissions.
[45CSR13: Permit R13-2334, 5.4.1.]

- 5.4.2. To determine compliance with the annual benzene emission limit set forth in Section 5.1.9., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of benzene present in petroleum liquids processed and transported at the facility. The following equation shall be to determine monthly and yearly emissions.

Benzene Emissions (tpm or tpy) = (Total VOCs (tpm or tpy)) x (Actual Benzene Vapor Weight %)

Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.
[45CSR13: Permit R13-2334, 5.4.2.]

- 5.4.3. To demonstrate compliance with the operational limit for the main/sour gas flare [F1] established in section 5.1.10., the permittee shall maintain records of the hours that non-pilot emissions were sent to the flare. The annual limit shall be recorded on a 12-month rolling total basis.
[45CSR13: Permit R13-2334, 5.4.3.]

- 5.4.4. The permittee shall meet all applicable notification and record keeping requirements of 40 CFR §60.7 for OXIDIZER, MLDOX, and NH3OX.
[45CSR16, 40 CFR §60.7, 45CSR13: Permit R13-2334, 5.4.4.]

- 5.4.5. The permittee shall retain records of the emissions estimates determined in 40 CFR §63.565(l) and requirement 5.3.4. of this permit and their actual throughputs by commodity for gasoline and light crude oil, for 5 years.
[45CSR34, 40 CFR §§63.560(a)(3) and 63.567(j)(4), 45CSR13: Permit R13-2334, 5.4.6.]

- 5.4.6. The tank truck vapor tightness documentation required under §60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.
[40 C.F.R. §60.505(a); 45CSR16] (T Load)

5.4.7. The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:

1. Test title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.
2. Tank owner and address.
3. Tank identification number.
4. Testing location.
5. Date of test.
6. Tester name and signature.
7. Witnessing inspector, if any: Name, signature, and affiliation.
8. Test results: Actual pressure change in 5 minutes, mm of water (average for 2 runs).

[40 C.F.R. §60.505(b); 45CSR16] (T Load)

5.4.8. A record of each monthly leak inspection required under §60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:

1. Date of inspection.
2. Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).
3. Leak determination method.
4. Corrective action (date each leak repaired; reasons for any repair interval in excess of 15 days).
5. Inspector name and signature.

[40 C.F.R. §60.505(c); 45CSR16] (T Load)

5.4.9. The terminal owner or operator shall keep documentation of all notifications required under §60.502(e)(4) on file at the terminal for at least 2 years.

[40 C.F.R. §60.505(d); 45CSR16] (T Load)

5.4.10. As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 40 C.F.R. §§60.505(a), (c), and (d) of this section, an owner or operator may comply with the requirements in either 40 C.F.R. §§60.505(e)(1) or (2).

1. An electronic copy of each record is instantly available at the terminal.
 - i. The copy of each record in 40 C.F.R. §§60.505(e)(1) is an exact duplicate image of the original paper record with certifying signatures.

- ii. The permitting authority is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R.§§60.505(e)(1).
- 2. For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.
 - i. The copy of each record in 40 C.F.R.§§60.505(e)(2) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The permitting authority is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R.§§60.505(e)(2).

[40 C.F.R. §60.505(e); 45CSR16] (T Load)

- 5.4.11. The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.

[40 C.F.R. §60.505(f); 45CSR16] (T Load)

- 5.4.12. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records of the test results for each gasoline cargo tank loading at the facility as specified in paragraphs (b)(1) through (3) of 40 C.F.R. §63.11094.
- 1. Annual certification testing performed under §63.11092(f)(1) and periodic railcar bubble leak testing performed under §63.11092(f)(2).
 - 2. The documentation file shall be kept up-to-date for each gasoline cargo tank loading at the facility. The documentation for each test shall include, as a minimum, the following information:
 - i. Name of test: Annual Certification Test—Method 27 or Periodic Railcar Bubble Leak Test Procedure.
 - ii. Cargo tank owner's name and address.
 - iii. Cargo tank identification number.
 - iv. Test location and date.
 - v. Tester name and signature.
 - vi. Witnessing inspector, if any: Name, signature, and affiliation.
 - vii. Vapor tightness repair: Nature of repair work and when performed in relation to vapor tightness testing.
 - viii. Test results: Test pressure; pressure or vacuum change, mm of water; time period of test; number of leaks found with instrument; and leak definition.

3. If you are complying with the alternative requirements in §63.11088(b), you must keep records documenting that you have verified the vapor tightness testing according to the requirements of the Administrator.

[40 C.F.R. §63.11094(b);45CSR34] (T Load)

- 5.4.13. As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 40 C.F.R. §63.11094(b), an owner or operator may comply with the requirements in either 40 C.F.R. §63.11094(c)(1) or (c)(2).
 1. An electronic copy of each record is instantly available at the terminal.
 - i. The copy of each record in 40 C.F.R. §63.11094(c)(1) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The Administrator is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R. §63.11094(c)(1).
 2. For facilities that use a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (e.g., via a card lock-out system), a copy of the documentation is made available (e.g., via facsimile) for inspection by the Administrator's delegated representatives during the course of a site visit, or within a mutually agreeable time frame
 - i. The copy of each record in 40 C.F.R. §63.11094(c)(2) is an exact duplicate image of the original paper record with certifying signatures.
 - ii. The Administrator is notified in writing that each terminal using this alternative is in compliance with 40 C.F.R. §63.11094(c)(2).

[40 C.F.R. §63.11094(c);45CSR34] (T Load)

- 5.4.14. Each owner or operator subject to the equipment leak provisions of §63.11089 shall prepare and maintain a record describing the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under §63.11089, the record shall contain a full description of the program.

[40 C.F.R. §63.11094(d);45CSR34] (T Load)

- 5.4.15. Each owner or operator of an affected source subject to equipment leak inspections under §63.11089 shall record in the log book for each leak that is detected the information specified in 40 C.F.R. §§63.11094(e)(1) through (7).
 1. The equipment type and identification number.
 2. The nature of the leak (i.e., vapor or liquid) and the method of detection (i.e., sight, sound, or smell).
 3. The date the leak was detected and the date of each attempt to repair the leak.
 4. Repair methods applied in each attempt to repair the leak.

5. “Repair delayed” and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak.
6. The expected date of successful repair of the leak if the leak is not repaired within 15 days.
7. The date of successful repair of the leak.

[40 C.F.R. §63.11094(e);45CSR34] (T Load)

- 5.4.16. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall:
1. Keep an up-to-date, readily accessible record of the continuous monitoring data required under §63.11092(b) or §63.11092(e). This record shall indicate the time intervals during which loadings of gasoline cargo tanks have occurred or, alternatively, shall record the operating parameter data only during such loadings. The date and time of day shall also be indicated at reasonable intervals on this record.
 2. Record and report simultaneously with the Notification of Compliance Status required under §63.11093(b):
 - i. All data and calculations, engineering assessments, and manufacturer's recommendations used in determining the operating parameter value under §63.11092(b) or §63.11092(e); and
 - ii. The following information when using a flare under provisions of §63.11(b) to comply with §63.11087(a):
 - A. Flare design (i.e., steam-assisted, air-assisted, or non-assisted); and
 - B. All visible emissions (VE) readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required under §63.11092(e)(3).
 3. Keep an up-to-date, readily accessible copy of the monitoring and inspection plan required under §63.11092(b)(1)(i)(B)(2) or §63.11092(b)(1)(iii)(B)(2).
 4. Keep an up-to-date, readily accessible record of all system malfunctions, as specified in §63.11092(b)(1)(i)(B)(2)(v) or §63.11092(b)(1)(iii)(B)(2)(v).
 5. If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in §63.11092(b), the owner or operator shall submit a description of planned reporting and recordkeeping procedures.

[40 C.F.R. §63.11094(f);45CSR34] (T Load)

- 5.4.17. Each owner or operator of an affected source under this subpart shall keep records as specified in 40 C.F.R. §63.11094(g)(1) and (2).

1. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
2. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.11085(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 C.F.R. §63.11094(g);45CSR34] (T Load)

5.4.18. General recordkeeping requirements.

1. The owner or operator shall comply with the recordkeeping requirements specified in §70.6(a)(3)(ii) of this chapter. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to §64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
2. 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 C.F.R. §64.9(b)] (MLDOX and NH3OX)

- 5.4.19. The temperature data for MLDOX and NH3OX shall be recorded and maintained in an electronic database and records shall be maintained for at least 5 years.

[45CSR§30-5.1.c; 40 C.F.R. §64.9(b)] (MLDOX and NH3OX)

5.5. Reporting Requirements

- 5.5.1. For the Main Flare [F1], the permittee shall comply with the reporting requirements of 40 CFR Part 60, Subpart Ja.
[45CSR16, 40 CFR§60.108a, 45CSR13: Permit R13-2334, 5.5.1.]
- 5.5.2. For the Sour Gas Flare [F2], the permittee shall comply with the reporting requirements of 40 CFR 60, Subpart J.
[45CSR16, 40 CFR §60.107(f), 45CSR13: Permit R13-2334, 5.5.2.]
- 5.5.3. The permittee shall meet all applicable reporting requirements of 40 CFR §60.19 for OXIDIZER, MLDOX, and NH3OX.
[45CSR16, 40 CFR §60.19, 45CSR13 - Permit R13-2334 - 5.5.3.]
- 5.5.4. Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:
 1. For loading racks, each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility.

2. For equipment leak inspections, the number of equipment leaks not repaired within 15 days after detection.

[40 C.F.R. §§63.11095(a)(2) and (3);45CSR34] (T Load)

- 5.5.5. Each owner or operator of an affected source subject to the control requirements of this subpart shall submit an excess emissions report to the Administrator at the time the semiannual compliance report is submitted. Excess emissions events under this subpart, and the information to be included in the excess emissions report, are specified in 40 C.F.R. §§63.11095(b)(1) through (5).
 1. Each instance of a non-vapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.
 2. Each reloading of a non-vapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.11094(b).
 3. Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.11092(b). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.
 4. Each instance in which malfunctions discovered during the monitoring and inspections required under §63.11092(b)(1)(i)(B)(2) and (b)(1)(iii)(B)(2) were not resolved according to the necessary corrective actions described in the monitoring and inspection plan. The report shall include a description of the malfunction and the timing of the steps taken to correct the malfunction.
 5. For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:
 - i. The date on which the leak was detected;
 - ii. The date of each attempt to repair the leak;
 - iii. The reasons for the delay of repair; and
 - iv. The date of successful repair.

[40 C.F.R. §63.11095(b); 45CSR34] (T Load)

- 5.5.6. Each owner or operator of a bulk gasoline plant or a pipeline pumping station shall submit a semiannual excess emissions report, including the information specified in 40 C.F.R. §63.11095(a)(3) and (b)(5), only for a 6-month period during which an excess emission event has occurred. If no excess emission events have occurred during the previous 6-month period, no report is required.

[40 C.F.R. §63.11095(c); 45CSR34] (T Load)

- 5.5.7. Each owner or operator of an affected source under this subpart shall submit a semiannual report including the number, duration, and a brief description of each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected

source to minimize emissions in accordance with §63.11085(a), including actions taken to correct a malfunction. The report may be submitted as a part of the semiannual compliance report, if one is required. Owners or operators of affected bulk plants and pipeline pumping stations are not required to submit reports for periods during which no malfunctions occurred.

[40 C.F.R. §63.11095(d); 45CSR34] (T Load)

5.5.8. General reporting requirements.

1. On and after the date specified in §64.7(a) by which the owner or operator must use monitoring that meets the requirements of this part, the owner or operator shall submit monitoring reports to the permitting authority in accordance with §70.6(a)(3)(iii) of this chapter.
2. A report for monitoring under this part shall include, at a minimum, the information required under §70.6(a)(3)(iii) of this chapter and the following information, as applicable:
 - i. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
 - ii. 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
 - iii. A description of the actions taken to implement a QIP during the reporting period as specified in §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 C.F.R. §64.9(a)] (MLDOX and NH3OX)

5.6. Compliance Plan

- 5.6.1. None.

6.0 Other Source Requirements [CDU, MEK-TOL, DHT-FUG, ISOM, UNIFINER, ADU, PL-FUG, and YNGL-FUG]

6.1. Limitations and Standards

- 6.1.1. Crude oil charge rate into the crude oil distillation unit shall not exceed 961,775 barrels per month and 9,617,750 barrels per year.

[45CSR13: Permit R13-2334, 6.1.1.]

- 6.1.2. Fugitive emissions of VOC's (MEK and Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 10.26 TPY. Fugitive emissions of HAPs (Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 5.09 TPY.

[45CSR13: Permit R13-2334, 6.1.2.]

- 6.1.3. The facility shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions:

- Leak Definition for Valves.** The facility shall utilize an internal leak definition of 500 ppm VOCs for the Refinery valves, excluding pressure relief devices.
- Leak Definition for Pumps.** The facility shall utilize an internal leak definition of 2000 ppm VOCs for the Refinery pumps.

[45CSR13: Permit R13-2334, 6.1.3.]

- 6.1.4. Fugitive emissions from the Diesel Hydrotreater [DHT-FUG], the Ammonia Destruction Unit [ADUFUG], the Platformer Expansion Unit [PL-FUG], and the Y-Grade NGL Unit [YNGL-FUG] shall not exceed the following:

Pollutant	DHT-FUG Fugitive Emissions	ADUFUG Fugitive Emissions	PL-FUG Fugitive Emissions	YNGL-FUG Fugitive Emissions
	ton/yr	ton/yr	ton/yr	ton/yr
VOC	13.20	0.34	0.60	0.94
Toluene	0.003	n/a	n/a	n/a
Ethyl Benzene	0.001	n/a	n/a	n/a
Xylene	0.04	n/a	n/a	n/a
Pentane	n/a	0.05	n/a	n/a
Hexane	n/a	0.02	0.04	0.03

[45CSR13: Permit R13-2334, 6.1.4.]

- 6.1.5. Fugitive emissions from the ISOM Unit shall not exceed 3.72 tpy VOC's and 0.85 tpy total HAP's.

[45CSR13: Permit R13-2334, 6.1.5.]

- 6.1.6. The permittee shall comply with the VOC equipment leak requirements of 40 CFR Part 60 Subpart VVa (as required by the applicability of 40 CFR Part 60, Subpart GGa) of affected facilities for which construction, reconstruction, or modification commenced after November 7, 2006 and Section 8.0 of this permit.

[45CSR13: Permit R13-2334, 6.1.6.]

6.2. Monitoring Requirements

6.2.1. None.

6.3. Testing Requirements

6.3.1. None.

6.4. Recordkeeping Requirements

6.4.1. To determine compliance with the crude oil charge rate limits set forth in Section 6.1.1., the permittee shall keep daily records along with monthly and yearly totals of the amount of crude oil charged to the crude oil distillation unit. Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13: Permit R13-2334, 6.2.1.]

6.4.2. To determine compliance with VOC fugitive emission rate limits set forth in Sections 6.1.2., 6.1.4., 6.1.5., and the internal leak definitions set forth in Section 6.1.3, the permittee shall comply with the requirements of 40 CFR Part 60 Subpart VV and apply the following Leak Detection and Repair (LDAR) program enhancements:

Emission Estimates. The permittee may use an enhanced LDAR program for controlling and estimating emissions on a monthly and yearly basis for the Solvent Dewaxing Unit. The permittee may use EPA's Correlation Approach, published in EPA's Protocol for Equipment Leak Emission Estimates, with measured screening values and hours of operation to determine compliance with the emission limits.

[45CSR13: Permit R13-2334, 6.2.2.]

6.5. Reporting Requirements

6.5.1. None.

6.6. Compliance Plan

6.6.1. None.

7.0 Tank Requirements

7.1. Limitations and Standards

7.1.1. Storage tanks are limited to the raw material/ product type and throughput provided in the table below:

Tank ID No.	Raw Material/Product Type and Throughput (Mgal ~~gallons~~ per year)
4000, 4001, 4060, 4061, and 4072	crude oil (802,264. ~~89~~ ,890 Mgal)
4062, 4063	crude oil and light crude oil w/vapor pressure up to 11.0 psia (306,600. ~~000~~)
4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, 4052, 4053, 4070, and 4071	gasoline or ethanol (325,070. ~~903~~ ,903)
4002, 4003, 4009, 4011, 4054, 4055, 4056, 4057, and 4073	heavy products or kerosene (406,459. ~~76~~ ,760)
4007, 4008, 4010, 4017, 4018, 4019, 4020, 4021, 4022, 4023, 4024, 4025, 4026, 4027, 4028, 4029, 4030, 4031, 4032, 4033, 4034, 4035, 4036, 4037, 4038, 4039, 4040, 4041, 4042, 4043, 4044, 4045, 4046, 4047, 4048, 4051, 4103, and 4104	heavy products (609,920. ~~249~~ ,249)
V-4002 and V-4003	Natural Gas Liquids

[45CSR13: Permit R13-2334, 7.1.1.]

7.1.2. Combined emissions from the tanks listed in section 7.1.1 shall not exceed the following:

Pollutant	Emission Rate	
	TPM	TPY
Total VOC	6.03	60.29
Benzene	0.09	0.85
Total HAP	0.69	6.86

[45CSR13: Permit R13-2334, 7.1.2.]

7.1.3. Fixed roof Tanks 4012 and 4013 shall be equipped with internal floating roofs to minimize emissions of VOC's.

[45CSR13: Permit R13-2334, 7.1.3.]

7.1.4. The following requirements apply to Tanks 4001, 4002, 4003, 4004, 4005, 4006, 4014, 4015, 4016:

- Each and every slotted guidepole that passes through the floating roof shall be equipped with one of the following: a pole float system; an alternate control technology that has an emission factor less than or equal to the emission factor for a pole float system; a pole sleeve system; an internal sleeve emission control system; a solid guidepole system; a flexible enclosure system; or
- In the alternative, the Permittee may elect to cover an external floating roof tank with a fixed roof mounted on the tank above the external floating roof, or remove the tank from the service storing liquids subject to NSPS Ka or Kb, modify the permit for that tank, and represent to the West Virginia Division of Air Quality that the tank will not be used to store certain petroleum liquids or volatile organic liquids.

- c. For systems that use a sliding cover, the sliding cover shall be in place over the slotted-guidepole opening in the floating roof at all times, except, when the sliding cover must be removed for access. If the control technology used includes a guidepole float, the float shall be floating within the guidepole at all times except when it must be removed for access to the stored liquid or when the tank is empty.
- d. The permittee shall visually inspect the deck fitting for the slotted guidepole at least once every ten (10) years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device has defects, or if a gap that is more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material.
- e. Tanks taken out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are taken out of service. Tanks taken out of service must have in place, prior to being put back into service, all controls necessary to remain below the emission limits set forth by the current version of permit R13-2334

[45CSR13: R13-2334, 7.1.4., 7.1.5.]

- 7.1.5. The following 40 CFR 60 Subpart K requirements apply to Tanks 4036, 4037, 4038, and 4039:

The owner or operator of any storage vessel to which 40 CFR Part 60 subpart K applies shall store petroleum liquids as follows: if the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

[40 CFR §60.112(a)(1) and 45CSR§16-4.1.; 45CSR13: Permit R13-2334, 7.1.6.]

- 7.1.6. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, 4046:

The owner or operator of each storage vessel to which 40 CFR Part 60 Subpart Ka applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

- 1. An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in 40 CFR §60.112a (a)(1)(ii)(D), the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
 - i. The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:
 - A. The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm² per meter of tank diameter (10.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

- B. The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).
 - C. One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.
 - D. There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
 - ii. The secondary seal is to meet the following requirements:
 - A. The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in 40 CFR §60.112a (a)(1)(ii)(B).
 - B. The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.
 - C. There are to be no holes, tears or other openings in the seal or seal fabric.
 - D. The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.
 - iii. Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in 40 CFR §60.112a (a)(1)(iv). Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.
 - iv. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.
- 2. A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set

to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

3. A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.
4. A system equivalent to those described in 40 CFR §60.112a (a)(1), (a)(2), or (a)(3) as provided in 40 CFR §60.114a.

[40 C.F.R. §60.112a(a) and 45CSR16]

7.1.7. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070 and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

- a. The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ 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 m³ but less than 151 m³ 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:
 1. A fixed roof in combination with an internal floating roof meeting the following specifications:
 - i. The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.
 - ii. Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:
 - A. A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.
 - B. Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.
 - C. A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

- iii. Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.
 - iv. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.
 - v. Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
 - vi. Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.
 - vii. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.
 - viii. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.
 - ix. Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.
2. An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:
- i. Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.
 - A. The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in 40 CFR §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.
 - B. The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in 40 CFR §60.113b(b)(4).
 - ii. Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed

on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

- iii. The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
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 40 CFR 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 (40 CFR §60.18) of the General Provisions.
4. A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) above as provided in 40 CFR §60.114b.
- b. The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m³ which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:
 1. A closed vent system and control device as specified in 40 CFR §60.112b(a)(3).
 2. A system equivalent to that described in paragraph (b)(1) as provided in 40 CFR §60.114b of this subpart.

[40 CFR §60.112b(a) and (b), 45CSR§16-4 .1., 45CSR13: Permit R13-2334, 7.1.7.]

- 7.1.8. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 60 Subpart Kb including but not limited to the following:
- a. Alternative means of compliance—(1) Option to comply with part 65. Owners or operators may choose to comply with 40 CFR Part 65, Subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR Part 65, Subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

[40 CFR §60.110b(e), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.8.]

- 7.1.9. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 65 Subparts C and G including but not limited to the following:

- a. Storage vessel requirements. The owner or operator expressly referenced to this subpart from Subpart C of this part shall comply with the following requirements, as applicable:

Route to a fuel gas system or process. Owners or operators subject to §65.42(b)(6) who route storage vessel emissions to a fuel gas system or to a process shall meet the requirements in §65.144 and the monitoring, recordkeeping, and reporting requirements referenced therein. No other provisions of this subpart apply to storage vessel emissions being routed to a fuel gas system or to a process.

[40 CFR §65.142(a)(3), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(a)]

- b. *Route to process or fuel gas system.* Route the emissions to a process or a fuel gas system as specified in §65.142(a)(3). Whenever the owner or operator bypasses the fuel gas system or process, the owner or operator shall comply with the recordkeeping requirement in §65.163(b)(3). Bypassing is permitted if the owner or operator complies with one or more of the following conditions:
- i. The liquid level in the storage vessel is not increased;
 - ii. The emissions are routed through a closed vent system to a control device complying with paragraph (b)(4) or (5) of this section; or
 - iii. The total aggregate amount of time during which the emissions bypass the fuel gas system or process during the calendar year without being routed to a control device, for all reasons (except startups/shutdowns/malfunctions or product changeovers of flexible operation units and periods when the storage vessel has been emptied and degassed), does not exceed 240 hours.

[40 CFR §65.42(b)(6), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(b)]

- c. Except during periods of startup, shutdown, and malfunction as specified in §65.3(a), the fuel gas system or process shall be operating at all times when regulated material emissions are routed to it.

[40 CFR §65.144(a)(1), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.1.9(c)]

- 7.1.10. You must meet each emission limit and management practice in Table 1 to 40 CFR 63 Subpart BBBBBB that applies to your gasoline storage tank.

If you own or operate ...	Then you must ...
2. A gasoline storage tank with a capacity of greater than or equal to 75 m ³ and not meeting any of the criteria specified in item 1 of this Table	(a) Reduce emissions of total organic HAP or TOC by 95 weight-percent with a closed vent system and control device, as specified in §60.112b(a)(3) of this chapter; or (b) Equip each internal floating roof gasoline storage tank (4012, 4013, and 4050) according to the requirements in §60.112b(a)(1) of this chapter, except for the secondary seal requirements under §60.112b(a)(1)(ii)(B) and the requirements in §60.112b(a)(1)(iv) through (ix) of this chapter; and (c) Equip each external floating roof gasoline storage tank (4004, 4005, 4006, 4014, 4015, 4016, and 4071) according to the requirements in §60.112b(a)(2) of this chapter, except that the requirements of §60.112b(a)(2)(ii) of this chapter shall only be required if such storage tank does not currently meet the requirements of §60.112b(a)(2)(i) of this chapter; or

If you own or operate ...	Then you must ...
	(d) Equip and operate each internal and external 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), and equip each external floating roof gasoline storage tank according to the requirements of §63.1063(a)(2) if such storage tank does not currently meet the requirements of §63.1063(a)(1).

[40 C.F.R. §63.11087(a); Table 1 to 40 C.F.R 63 Subpart BBBBBB, 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.2. Monitoring Requirements

- 7.2.1. Compliance with Section 7.1.4. may be determined by visual inspection by the Director or a duly authorized representative of the Director.

[45CSR13: Permit R13-2334, 7.2.1.]

- 7.2.2. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

The owner or operator of each storage vessel as specified in 40 CFR §60.112b(a) shall meet the requirements of paragraph a., b., or c. of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of 40 CFR §60.112b.

- a. After installing the control equipment required to meet 40 CFR §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:
 1. Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.
 2. For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in 40 CFR §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.
 3. For vessels equipped with a double-seal system as specified in 40 CFR §60.112b(a)(1)(ii)(B) :

- i. Visually inspect the vessel as specified in paragraph a.4. of this section at least every 5 years; or
 - ii. Visually inspect the vessel as specified in paragraph a.2. of this section.
- 4. Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs a.2. and a.3.ii. of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph a.3.i. of this section.
- 5. Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs a.1. and a.4. of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph a.4. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.
- b. After installing the control equipment required to meet 40 CFR §60.112b(a)(2) (external floating roof), the owner or operator shall:
 - 1. Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.
 - i. Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.
 - ii. Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.
 - iii. If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs b.1.i. and b.1.ii. of this section.
 - 2. Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

- i. Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - ii. Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.
 - iii. The total surface area of each gap described in paragraph b.2.ii. of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
3. Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph b.4. of this section.
4. Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 40 CFR §60.113b(b)(4) (i) and (ii).
5. Notify the Administrator 30 days in advance of any gap measurements required by paragraph b.1. of this section to afford the Administrator the opportunity to have an observer present.
6. Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.
 - i. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.
 - ii. For all the inspections required by paragraph b.6. of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph b.6. of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.
- c. 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.

1. 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.
 - 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 40 CFR Part 60 subpart K, 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 816C 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).
 2. 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 c.1. of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.
 - d. The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in 40 CFR §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, 40 CFR §60.18 (e) and (f).
[40 C.F.R. §60.113b, 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.2.2.]
- 7.2.3. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, and 4046:
- a. Except as provided in 40 CFR §60.8(b) compliance with the standard prescribed in 40 CFR §60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in 40 CFR §60.114a.
 1. The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:
 - i. Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:
 - A. For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

- B. For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.
 - C. If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs 40 CFR §§60.113a(a)(1)(i)(A) and (a)(1)(i)(B).
 - D. Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by 40 CFR §60.113a(a)(1)(ii) and the calculation required by 40 CFR 60.113a(a)(1)(iii).
 - E. If either the seal gap calculated in accord with 40 CFR §60.113a (a)(1)(iii) or the measured maximum seal gap exceeds the limitations specified by 40 CFR §60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of 40 CFR §60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of 40 CFR §60.112a.
- ii. Determine gap widths in the primary and secondary seals individually by the following procedures:
 - A. Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - B. Measure seal gaps around the entire circumference of the tank in each place where a $\frac{1}{8}$ " diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.
 - C. The total surface area of each gap described in 40 CFR §60.113a (a)(1)(ii)(B) shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
 - iii. Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in 40 CFR §60.112a(a)(1)(i) and §60.112a(a)(1)(ii).
 - iv. Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.
- 2. The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

- i. Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.
- ii. The manufacturer's design specifications and estimated emission reduction capability of the system.
- iii. The operation and maintenance plan for the system.
- iv. Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

[40 CFR §60.113a and 45CSR16]

7.2.4. The following 40 CFR 60 Subpart Kb requirements apply to Tanks V-4002 and V-4003:

- (e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 - (1) For 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 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.
 - (2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - (i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
 - (ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.
 - (3) For other liquids, the vapor pressure:
 - (i) May be obtained from standard reference texts, or
 - (ii) Determined by ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17); or
 - (iii) Measured by an appropriate method approved by the Administrator; or
 - (iv) Calculated by an appropriate method approved by the Administrator.

[40 CFR §60.116b(e) and 45CSR16]

7.3. Testing Requirements

7.3.1. Each owner or operator subject to the emission standard in §63.11087 for gasoline storage tanks shall comply with the requirements in 40 C.F.R. §§63.11092(e)(1) through (3).

(1) If your gasoline storage tank is equipped with an internal floating roof, you must perform inspections of the floating roof system according to the requirements of 40 C.F.R. §60.113b(a) if you are complying with option 2(b) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB, or according to the requirements of 40 C.F.R. §63.1063(c)(1) if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB. **(4012, 4013, and 4050)**

(2) If your gasoline storage tank is equipped with an external floating roof, you must perform inspections of the floating roof system according to the requirements of 40 C.F.R. §60.113b(b) if you are complying with option 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB, or according to the requirements of 40 C.F.R. §63.1063(c)(2) if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBBBB. **(4004, 4005, 4006, 4014, 4015, 4016, and 4071)**

[40 C.F.R. §63.11092(e); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.4. Recordkeeping Requirements

7.4.1. To determine compliance with the throughput limits set forth in Section 7.1.1. and the VOC emission limit set forth in Section 7.1.2., the permittee shall keep monthly records of throughput of each raw material/product for each tank. These records shall be kept individually, i.e. per tank. AP-42 emission factors for organic liquid storage tanks (Supp. D, Chapter 7.1), may be used to estimate yearly emissions.

[45CSR13: Permit R13-2334, 7.3.1., 45CSR§30-5.1.c.]

7.4.2. To determine compliance with the short-term and annual HAP emission limits set forth in Section 7.1.2., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of HAPs present in petroleum liquids processed and transported at the facility. The following equation shall be used to determine monthly and yearly emissions.

HAP Emissions (tpm or tpy) = [(Individual HAP %) x (Actual VOC emissions, obtained from section 7.4.1. (tpm or tpy))]/100

Compliance with the yearly limit shall be based on a 12-month rolling total in accordance with Section 2.1.4.

[45CSR13: Permit R13-2334, 7.3.2., 45CSR§30-5.1.c.]

7.4.3. The following 40 CFR 60 Subpart K requirements apply to Tanks 4036, 4037, 4038, and 4039:

Except as provided in 40 CFR §60.113(d), the owner or operator subject to 40 CFR Part 60 subpart K shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

[40 CFR §60.113(a), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.3.]

7.4.4. The following 40 CFR 60 Subpart Ka requirements apply to Tanks 4035, 4040, 4042, 4043, 4044, 4045, and 4046:

- a. Except as provided in 40 CFR §§60.115a (d), the owner or operator subject to 40 CFR Part 60 Subpart Ka shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.
- b. Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
- c. The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

[40 CFR §§60.115a(a) through (c) and 45CSR16]

7.4.5. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, and 4071. Based on storage of heavy products, Tanks 4034, 4047, 4048, 4051, 4054, 4055, 4056, and 4057 are not subject to either the floating roof requirements or the closed vent system and control requirements of 40 CFR 60 Subpart Kb.

The owner or operator of each storage vessel as specified in 40 CFR §60.112b (a) shall keep records and furnish reports as required by 40 CFR §60.115b (a), (b), or (c) depending upon the control equipment installed to meet the requirements of 40 CFR §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by 40 CFR §60.115b (c) (1), for at least 2 years. The record required by 40 CFR §60.115b (c)(1) will be kept for the life of the control equipment.

- a. After installing control equipment in accordance with 40 CFR §60.112b (a) (1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.
 1. Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR §60.112b (a)(1) and 40 CFR §60.113b (a)(1). This report shall be an attachment to the notification required by 40 CFR §60.7 (a)(3).
 2. Keep a record of each inspection performed as required by 40 CFR §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).
 3. If any of the conditions described in 40 CFR §60.113b (a)(2) are detected during the annual visual inspection required by 40 CFR §60.113b (a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.
 4. After each inspection required by 40 CFR §60.113b (a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in 40 CFR §60.113b (a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection.

The report shall identify the storage vessel and the reason it did not meet the specifications of 40 CFR §60.112b (a)(1) or 40 CFR §60.113b (a)(3) and list each repair made.

- b. After installing control equipment in accordance with 40 CFR §60.112b (a)(2) (external floating roof), the owner or operator shall meet the following requirements.
 1. Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR §60.112b (a)(2) and 40 CFR §60.113b (b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by 40 CFR §60.7(a)(3).
 2. Within 60 days of performing the seal gap measurements required by 40 CFR §60.113b (b)(1), furnish the Administrator with a report that contains:
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in 40 CFR §§60.113b (b)(2) and (b)(3).
 3. Keep a record of each gap measurement performed as required by 40 CFR §60.113b (b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:
 - i. The date of measurement.
 - ii. The raw data obtained in the measurement.
 - iii. The calculations described in 40 CFR §§60.113b (b)(2) and (b)(3).
 4. After each seal gap measurement that detects gaps exceeding the limitations specified by 40 CFR §60.113b (b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in 40 CFR §60.115b (b)(2) and the date the vessel was emptied or the repairs made and date of repair.
- c. 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.
 1. A copy of the operating plan.
 2. A record of the measured values of the parameters monitored in accordance with 40 CFR §60.113b(c)(2).
- d. After installing a closed vent system and flare to comply with 40 CFR §60.112b, the owner or operator shall meet the following requirements.
 1. A report containing the measurements required by 40 CFR §§60.18 (f)(1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by 40 C.F.R. §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

2. Records shall be kept of all periods of operation during which the flare pilot flame is absent.
3. Semiannual reports of all periods recorded under 40 CFR §60.115b (d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

[40 CFR §60.115b, 45CSR§16-4.1.; 45CSR13: Permit R13-2334, 7.3.4.]

7.4.6. The following 40 CFR 60 Subpart Kb requirements apply to Tanks 4000, 4004, 4005, 4006, 4034, 4047, 4048, 4050, 4051, 4054, 4055, 4056, 4057, 4060, 4061, 4062, 4063, 4070, 4071, and 4073:

- a. The owner or operator shall keep copies of all records required by 40 CFR Part 60 Subpart Kb, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section 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 and an analysis showing the capacity of the storage vessel.
- c. Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa 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.
- d. Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.
- e. Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.
 1. For 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 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.
 2. For crude oil or refined petroleum products the vapor pressure may be obtained by the following:
 - i. Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference -- see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

- ii. The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.
- f. The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.
 - 1. Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.
 - 2. For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in 40 CFR §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:
 - i. ASTM D2879-83, 96, or 97 (incorporated by reference -- see 40 CFR §60.17); or
 - ii. ASTM D323-82 or 94 (incorporated by reference -- see 40 CFR §60.17); or
 - iii. As measured by an appropriate method as approved by the Administrator.
- g. The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of 40 CFR §60.112b or with emissions reductions equipment as specified in 40 CFR §65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[40 CFR §60.116b, 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.5.]

- 7.4.7. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 65 Subparts C and G including but not limited to the following:
- a. Bypass records for storage vessel emissions routed to a process or fuel gas system. An owner or operator who uses the bypass provisions of §65.144(a)(2) shall keep in a readily accessible location the following records:
 - i. The reason it was necessary to bypass the process equipment or fuel gas system;
 - ii. The duration of the period when the process equipment or fuel gas system was bypassed;
 - iii. Documentation or certification of compliance with the applicable provisions of §65.42(b)(6).

[40 CFR §65.163(b)(3), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(a)]

- b. Vessel dimensions and capacity. Each owner or operator of a storage vessel subject to this subpart shall keep readily accessible records showing the dimensions of the storage vessel and an analysis of the capacity of the storage vessel.

[40 CFR §65.47(b), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(b)]

- c. Regulated source and control equipment startup, shutdown and malfunction records. (1) Records of the occurrence and duration of each startup, shutdown, and malfunction of process equipment or of air pollution control equipment used to comply with this part during which excess emissions (as defined in §65.3(a)(4)) occur.

[40 CFR §65.163(c), 45CSR§16-4.1., 45CSR13: Permit R13-2334, 7.3.6(c)]

- 7.4.8. Tanks V-4002 and V-4003 shall comply with all applicable provisions of 40 CFR 60 Subpart A including but not limited to the following:

- a. Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

1. A notification of the date construction (or reconstruction as defined under 40 CFR §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

[40 CFR §60.7(a)(1), 45CSR§16-4.1]

- 7.4.9. Each owner or operator of a bulk gasoline terminal or pipeline breakout station whose storage vessels are subject to the provisions of this subpart shall keep records as specified in 40 C.F.R. §60.115b of this chapter if you are complying with options 2(a), 2(b), or 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBB, except records shall be kept for at least 5 years. If you are complying with the requirements of option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBB, you shall keep records as specified in 40 C.F.R. §63.1065.

[40 C.F.R. §63.11094(a); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.5. Reporting Requirements

- 7.5.1. Each owner or operator of a bulk terminal or a pipeline breakout station subject to the control requirements of this subpart shall include in a semiannual compliance report to the Administrator the following information, as applicable:

- (1) For storage vessels, if you are complying with options 2(a), 2(b), or 2(c) in Table 1 of 40 C.F.R. 63 Subpart BBBB, the information specified in 40 C.F.R. §60.115b(a), 40 C.F.R. §60.115b(b), or 40 C.F.R. §60.115b(c), depending upon the control equipment installed, or, if you are complying with option 2(d) in Table 1 of 40 C.F.R. 63 Subpart BBBB, the information specified in 40 C.F.R. §63.1066.

[40 C.F.R. §63.11095(a); 45CSR34] (4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, and 4071)

7.6. Compliance Plan

- 7.6.1. None.

8.0 Equipment Leak Detection and Repair Requirements

8.1. Limitations and Standards

8.1.1. **Training.** The permittee shall implement the following training programs at the facility:

- a. For personnel newly-assigned to LDAR responsibilities, EWVI shall require LDAR training prior to each employee beginning such work;
- b. For all personnel assigned LDAR responsibilities, EWVI shall provide and require completion of annual LDAR training; and
- c. For all other Refinery operations and maintenance personnel (including contract personnel), EWVI shall provide and require completion of an initial training program that includes instruction on aspects of LDAR that are relevant to the person's duties. Refresher training in LDAR shall be performed on a three-year cycle.

[45CSR13: Permit R13-2334, 8.1.1., 45CSR§30-12.7]

8.1.2. **LDAR Personnel.** The permittee shall establish a program that will hold LDAR personnel accountable for LDAR performance. The permittee shall maintain a position within the facility responsible for LDAR management, with the authority to implement improvements.

[45CSR13: Permit R13-2334, 8.1.2., 45CSR§30-12.7]

8.1.3. **Internal Leak Definition for Valves and Pumps; Compressor Compliance.** The permittee shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions.

- a. Leak Definition for Valves. The permittee shall utilize an internal leak definition of 500 ppm VOCs for the valves at the facility, excluding pressure relief devices.
- b. Leak Definition for Pumps. The permittee shall utilize an internal leak definition of 2000 ppm VOCs for the pumps at the facility.

[45CSR13: Permit R13-2334, 8.1.3., 45CSR§30-12.7]

8.1.4. **First Attempt at Repairs on Valves.** The permittee shall make a "first attempt" at repair on any valve that has a reading greater than 200 ppm of VOCs, excluding control valves, pumps, and components that LDAR personnel are not authorized to repair. The permittee, or its designated contractor, however, shall re-monitor, within 5 business days, all valves that LDAR personnel attempted to repair. Unless the re-monitored leak rate is greater than the applicable leak definition, no further action will be necessary.

[45CSR13: Permit R13-2334, 8.1.4., 45CSR§30-12.7]

8.1.5. **Delay of Repair.** For any equipment for which the permittee is allowed, under the applicable regulations, to place on the "delay of repair" list for repair:

- a. For all equipment, the permittee shall:

1. Require sign-off by the unit supervisor or shift supervisor that the piece of equipment is technically infeasible to repair without a process unit shutdown, before the component is eligible for inclusion on the “delay of repair” list; and
2. Include equipment that is placed on the “delay of repair” list in the permittee’s regular LDAR monitoring.
- b. For valves: For valves, other than control valves, leaking at a rate of 10,000 ppm or greater, the permittee shall continue to use its “drill and tap” method for fixing such leaking valves, rather than placing the valve on the “delay of repair” list, unless the permittee can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner. After two unsuccessful attempts to repair a leaking valve through the drill and tap method, the permittee may place the leaking valve on its “delay of repair” list. If a new method develops for repairing such valves, the permittee will advise EPA prior to implementing such new method.
- c. For pumps: For pumps leaking at a rate of 2000 ppm or greater, the permittee shall undertake its best efforts to isolate and repair such pumps with a first attempt at fifteen (15) days.

[45CSR13: Permit R13-2334, 8.1.5., 45CSR§30-12.7]

- 8.1.6. a. 1. The provisions of 40 CFR Part 60 Subpart GGGa apply to affected facilities in petroleum refineries.
2. A compressor is an affected facility.
3. The group of all the equipment (defined in 40 CFR §60.591a) within a process unit is an affected facility.
- b. Any affected facility under 40 CFR §60.590a(a) that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of 40 CFR Part 60 Subpart GGGa.
- c. Addition or replacement of equipment (defined in 40 CFR §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under 40 CFR Part 60 Subpart GGGa.

[45CSR16, 40 CFR §§60.590a (a) through (c)]

- 8.1.7. a. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGGa shall comply with the requirements of 40 CFR §§60.482-1a to 60.482-10a as soon as practicable, but no later than 180 days after initial startup.
- b. For a given process unit, an owner or operator may elect to comply with the requirements of 40 CFR §60.592a (b)(1), (2), or (3) as an alternative to the requirements in 40 CFR §60.482-7a.
1. Comply with 40 CFR §60.483-1a.
 2. Comply with 40 CFR §60.483-2a.
 3. Comply with the Phase III provisions in 40 CFR §63.168, except an owner or operator may elect to follow the provisions in 40 CFR §60.482-7a (f) instead of 40 CFR §63.168 for any valve that is designated as being leakless.

- c. An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of 40 CFR §60.484a.
- d. Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 40 CFR §60.485a except as provided in 40 CFR §60.593a.
- e. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGa shall comply with the provisions of 40 CFR §§60.486a and 60.487a.

[45CSR16, 40 CFR §60.592a]

- 8.1.8.
- a. Each owner or operator subject to the provisions of 40 CFR Part 60 Subpart GGa may comply with the following exceptions to the provisions of 40 CFR Part 60 Subpart VVa.
 - 1. Compressors in hydrogen service are exempt from the requirements of 40 CFR §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.
 - 2. Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260-73, 91, or 96, E168-67, 77, or 92, or E169-63, 77, or 93 (incorporated by reference as specified in 40 CFR §60.17) shall be used.
 - 3.
 - i. An owner or operator may use engineering judgment rather than procedures in 40 CFR §60.593a (b)(2) to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in 40 CFR §60.593a (b)(2) shall be used to resolve the disagreement.
 - ii. If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in 40 CFR §60.593a (b)(2).
 - c. Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from 40 CFR §§60.482-3a (a) through (e) and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §§60.482-3a (a) through (e) and (h).
 - d. An owner or operator may use the following provision in addition to 40 CFR §60.485a (e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86-78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in 40 CFR §60.17).

- e. Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of 40 CFR §§60.482-2a and 60.482-7a.
- f. Open-ended valves or lines containing asphalt as defined in 40 CFR §60.591a are exempt from the requirements of 40 CFR §§60.482-6a (a) through (c).
- g. Connectors in gas/vapor or light liquid service are exempt from the requirements in 40 CFR §60.482-11a, provided the owner or operator complies with 40 CFR §60.482-8a for all connectors, not just those in heavy liquid service.

[45CSR16, 40 CFR §60.593a]

- 8.1.9. Any affected facility under 40 CFR §60.480a (a) that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of 40 CFR Part 60 Subpart VVa unless other permit requirements require more stringent requirements.

[45CSR13: R13-2334, 8.1.6., 45CSR16, 40 CFR §§60.480a (b)]

Standards: General

- 8.1.10. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall demonstrate compliance with the requirements of 40 CFR §§60.482-1a through 60.482-10a or 40 CFR §60.480a (e) for all equipment within 180 days of initial startup.
- b. Compliance with §§60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.
- c. 1. The permittee may request a determination of equivalence of a means of emission limitation to the requirements of 40 CFR §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in 40 CFR §60.484a.
2. If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of 40 CFR §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, or 60.482-10a, the permittee shall comply with the requirements of that determination.
- d. Equipment that is in vacuum service is excluded from the requirements of §§60.482-2a through 60.482-10a if it is identified as required in 40 C.F.R. §60.486a (e)(5).
- e. Equipment that the permittee designates as being in VOC service less than 300 hr/yr is excluded from the requirements of 40 CFR §§60.482-2a through 60.482-11a if it is identified as required in §60.486a (e) (6) and it meets any of the conditions specified in 40 CFR §§60.482-1a (e) (1) through (3).
- 1. The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.
 - 2. The equipment is in VOC service only during process malfunctions or other emergencies.

3. The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.
- f. 1. If a dedicated batch process unit operates less than 365 days during a year, the permittee may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in 40 CFR §§60.482-2a, 60.482-7a, and 60.483-2a

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually
25 to <50	Quarterly	Semiannually	Annually
50 to <75	Bimonthly	Three quarters	Semiannually
75 to 100	Monthly	Quarterly	Semiannually

2. Pumps and valves that are shared among two or more batch process units that are subject to 40 CFR Part 60 Subpart VVa may be monitored at the frequencies specified in 40 CFR §60.482-1a (f)(1), provided the operating time of all such process units is considered.
3. The monitoring frequencies specified in 40 CFR §60.482-1a (f)(1) are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. The permittee may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in 40 CFR §§60.482-1a (f)(3)(i) through (iv).
- i. When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.
- ii. When monitoring is conducted semiannually (i.e. , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.
- iii. When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.
- iv. When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.
- g. If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to 40 CFR Part 60 Subpart VVa, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to 40 CFR Part 60 Subpart VVa, the storage vessel is assigned to any process unit subject to 40 CFR Part 60 Subpart VV. If the predominant use of the storage vessel varies from year to year, then the permittee must estimate the predominant use initially and reassess every 3 years. The permittee must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

[45CSR16, 40 CFR §60.482-1a, 45CSR13: R13-2334, 8.1.6.]

Standards: Pumps in Light Liquid Service

- 8.1.11. a. 1. Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR §60.485a (b), except as provided in 40 CFR §§60.482-1a (c) and (f) and 40 CFR §§60.482-2a (d), (e), and (f). 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 40 CFR §60.482-1a (c) and 40 CFR §§60.482-2a (d), (e), and (f).
2. Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in 40 CFR §60.482-1a (f).
- b. 1. The instrument reading that defines a leak is specified in 40 CFR §§60.482-2a (b)(1)(i) and (ii).
- i. 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
- ii. 2,000 ppm or greater for all other pumps.
2. If there are indications of liquids dripping from the pump seal, the permittee shall follow the procedure specified in either 40 CFR §60.482-2a (b)(2)(i) or (ii). This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in 40 CFR § 60.482-2a (b)(1)(i) or (ii), whichever is applicable.
- i. Monitor the pump within 5 days as specified in 40 CFR § 60.485a (b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in 40 CFR § 60.482-2a (b)(1)(i) or (ii), whichever is applicable. The leak shall be repaired using the procedures in 40 CFR § 60.482-2a (c).
- ii. Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in 40 CFR § 60.482-2a (c) or by eliminating the visual indications of liquids dripping.
- c. 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in 40 CFR §§ 60.482-2a (c)(2)(i) and (ii), where practicable.
- i. Tightening the packing gland nuts;
- ii. Ensuring that the seal flush is operating at design pressure and temperature
- d. Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of 40 CFR § 60.482-2a (a), provided the requirements specified in 40 CFR §§ 60.482-2a (d)(1) through (6) are met.
1. Each dual mechanical seal system is:

- i. Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or
 - ii. 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 40 CFR § 60.482-10a; or
 - iii. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
2. The barrier fluid system is in heavy liquid service or is not in VOC service.
3. Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.
4.
 - i. Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.
 - ii. If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the permittee shall follow the procedure specified in either 40 C.F.R. § 60.482-2a (d) (4) (ii) (A) or (B) prior to the next required inspection.
 - A. Monitor the pump within 5 days as specified in 40 CFR § 60.485a (b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.
 - B. Designate the visual indications of liquids dripping as a leak.
5.
 - i. Each sensor as described in 40 CFR § 60.482-2a (d)(3) is checked daily or is equipped with an audible alarm.
 - ii. 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.
 - iii. If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in 40 CFR § 60.482-2a (d)(5)(ii), a leak is detected.
6.
 - i. When a leak is detected pursuant to 40 CFR § 60.482-2a (d)(4)(ii)(A), it shall be repaired as specified in 40 CFR § 60.482-2a (c).
 - ii. A leak detected pursuant to 40 CFR § 60.482-2a (d)(5)(iii) shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.
 - iii. A designated leak pursuant to 40 CFR § 60.482-2a (d)(4)(ii)(B) shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.
- e. Any pump that is designated, as described in 40 CFR §§ 60.486a (e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR §§ 60.482-2a (a), (c), and (d) if the pump:

1. Has no externally actuated shaft penetrating the pump housing;
 2. Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 C.F.R. § 60.485a (c); and
 3. Is tested for compliance with 40 CFR § 60.482-2a (e)(2) initially upon designation, annually, and at other times requested by the Administrator.
- f. 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 or to a fuel gas system or to a control device that complies with the requirements of 40 CFR § 60.482-10a, it is exempt from 40 CFR §§ 60.482-2a (a) through (e).
- g. Any pump that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 40 CFR §§ 60.482-2a (a) and (d)(4) through (6) if:
1. The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 C.F.R. § 60.482-2a (a); and
 2. The owner or operator of the pump 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 repair of the equipment according to the procedures in 40 CFR § 60.482-2a (c) if a leak is detected.
- h. Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of 40 CFR §§ 60.482-2a (a)(2) and (d)(4), and the daily requirements of 40 CFR § 60.482-2a (d)(5), provided that each pump is visually inspected as often as practicable and at least monthly.

[45CSR16, 40 CFR § 60.482-2a, 45CSR13, R13-2334, 8.1.6.]

Standards: Compressors

- 8.1.12. a. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR §§ 60.482-3a (h), (i), and (j).
- b. Each compressor seal system as required in 40 CFR § 60.482-3a (a) shall be:
1. Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or
 2. Equipped with a barrier fluid system 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 40 CFR § 60.482-10a; or

3. Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.
- c. The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.
- d. Each barrier fluid system as described in 40 CFR § 60.482-3a (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.
- e.
 1. Each sensor as required in 40 CFR § 60.482-3a (d) shall be checked daily or shall be equipped with an audible alarm.
 2. The permittee shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.
- f. If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under 40 CFR § 60.482-3a (e)(2), a leak is detected.
- g.
 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
 2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- h. A compressor is exempt from the requirements of 40 CFR §§ 60.482-3a (a) and (b), if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of 40 CFR § 60.482-10a, except as provided in paragraph (i) of this section.
- i. Any compressor that is designated, as described in 40 CFR §§ 60.486a (e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR §§ 60.482-3a (a) through (h) if the compressor:
 1. Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in 40 CFR § 60.485a (c); and
 2. Is tested for compliance with 40 CFR § 60.482-3a (i)(1) initially upon designation, annually, and at other times requested by the Administrator.
- j. Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of 40 CFR § 60.14 or 40 CFR § 60.15 is exempt from 40 CFR §§ 60.482-3a (a) through (e) and (h), provided the permittee demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §§ 60.482-3a (a) through (e) and (h).

[45CSR16, 40 CFR § 60.482-3a, 45CSR13: R13-2334, 8.1.6]

Standards: Pressure relief devices in gas/vapor service.

- 8.1.13. a. Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR § 60.485a (c).
- b. 1. After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR § 60.482-9a.
2. No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR § 60.485a (c).
- c. 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 40 CFR § 60.482-10a is exempted from the requirements of 40 CFR §§ 60.482-4a (a) and (b).
- d. 1. Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of 40 CFR §§ 60.482-4a (a) and (b), provided the permittee complies with the requirements in 40 CFR § 60.482-4a (d)(2).
2. After each pressure release, a new rupture disk shall be installed 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 40 CFR § 60.482-9a.

[45CSR16, 40 CFR § 60.482-4a, 45CSR13: R13-2334, 8.1.6.]

Standards: Sampling connection systems.

- 8.1.14. a. Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR § 60.482-5a (c).
- b. Each closed-purge, closed-loop, or closed-vent system as required in 40 CFR § 60.482-5a (a) shall comply with the requirements specified in 40 CFR §§ 60.482-5a (b)(1) through (4).
1. Gases displaced during filling of the sample container are not required to be collected or captured.
2. Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.
3. Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.
4. Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either 40 C.F.R. §§ 60.482-5a (b) (4) (i), (ii), (iii), or (iv).

- i. Return the purged process fluid directly to the process line.
- ii. Collect and recycle the purged process fluid to a process.
- iii. Capture and transport all the purged process fluid to a control device that complies with the requirements of 40 CFR § 60.482-10a.
- iv. Collect, store, and transport the purged process fluid to any of the following systems or facilities:
 - A. A waste management unit as defined in 40 CFR § 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR Part 63 Subpart G, applicable to Group 1 wastewater streams;
 - B. A treatment, storage, or disposal facility subject to regulation under 40 CFR Part 262, 264, 265, or 266;
 - C. A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR Part 261;
 - D. A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR § 61.348 (a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR. § 61.343 through 40 CFR § 61.347; or
 - E. A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR Part 279 Subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR Part 261.
- c. In-situ sampling systems and sampling systems without purges are exempt from the requirements of 40 CFR §§ 60.482-5a (a) and (b).

[45CSR16, 40 CFR § 60.482-5a, 45CSR13: R13-2334, 8.1.6.]

Standards: Open-ended valves or lines.

- 8.1.15. a.
 - 1. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR § 60.482-1a (c) and 40 CFR §§ 60.482-6a (d) and (e).
 - 2. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.
- b. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

- c. 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 comply with 40 CFR § 60.482-6a (a) at all other times.
- d. 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 §§ 60.482-6a (a), (b), and (c).
- e. 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 40 CFR §§ 60.482-6a (a) through (c) are exempt from the requirements of 40 CFR §§ 60.482-6a (a) through (c).

[45CSR16, 40 CFR § 60.482-6a, 45CSR13, R13-2334, 8.1.6.]

Standards: Valves in gas/vapor service and in light liquid service.

- 8.1.16. a. 1. Each valve shall be monitored monthly to detect leaks by the methods specified in 40 CFR § 60.485a (b) and shall comply with 40 CFR §§ 60.482-7a (b) through (e), except as provided in 40 CFR §§ 60.482-7a (f), (g), and (h), 40 CFR §§ 60.482-1a (c) and (f), and 40 CFR §§ 60.483-1a and 60.483-2a.
2. A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to 40 CFR § 60.482-7a (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in 40 CFR §§ 60.482-7a (f), (g), and (h), 40 CFR § 60.482-1a (c), and 40 CFR §§ 60.483-1a and 60.483-2a.
- i. Monitor the valve as in 40 CFR § 60.482-7a (a)(1). The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.
 - ii. If the existing valves in the process unit are monitored in accordance with 40 CFR § 60.483-1a or 40 CFR § 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in 40 C.F.R. § 60.483-2a (b) (5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.
- b. If an instrument reading of 500 ppm or greater is measured, a leak is detected.
- c. 1. i. Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.
- ii. As an alternative to monitoring all of the valves in the first month of a quarter, the permittee may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The permittee must keep records of the valves assigned to each subgroup.
2. If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

- d.
 1. When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR § 60.482-9a.
 2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- e. First attempts at repair include, but are not limited to, the following best practices where practicable:
 1. Tightening of bonnet bolts;
 2. Replacement of bonnet bolts;
 3. Tightening of packing gland nuts;
 4. Injection of lubricant into lubricated packing.
- f. Any valve that is designated, as described in 40 CFR § 60.486a (e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of 40 CFR § 60.482-7a (a) if the valve:
 1. Has no external actuating mechanism in contact with the process fluid,
 2. Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR § 60.485a (c), and
 3. Is tested for compliance with 40 CFR § 60.482-7a (f)(2) initially upon designation, annually, and at other times requested by the Administrator.
- g. Any valve that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 40 CFR § 60.482-7a (a) if:
 1. The permittee of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR § 60.482-7a (a), and
 2. The permittee of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.
- h. Any valve that is designated, as described in 40 CFR § 60.486a (f)(2), as a difficult-to-monitor valve is exempt from the requirements of 40 CFR § 60.482-7a (a) if:
 1. The permittee of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
 2. The process unit within which the valve is located either:
 - i. Becomes an affected facility through 40 CFR § 60.14 or 40 CFR § 60.15 and was constructed on or before January 5, 1981; or

- ii. Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the permittee.
- 3. The permittee of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[45CSR16, 40 CFR § 60.482-7a, 45CSR13: R13-2334, 8.1.6.]

Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.

- 8.1.17. a. If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the permittee shall follow either one of the following procedures:
 - 1. The permittee shall monitor the equipment within 5 days by the method specified in 40 CFR § 60.485a (b) and shall comply with the requirements of 40 CFR §§ 60.482-8a (b) through (d).
 - 2. The permittee shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.
- b. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.
- c.
 - 1. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a.
 - 2. The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.
- d. First attempts at repair include, but are not limited to, the best practices described under 40 CFR §§ 60.482-2a (c)(2) and 60.482-7a (e).

[45CSR16, 40 CFR § 60.482-8a, 45CSR13: R13-2334, 8.1.6.]

Standards: Delay of repair.

- 8.1.18. a. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment 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.
- b. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.
- c. Delay of repair for valves and connectors will be allowed if:
 - 1. 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

2. When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR § 60.482-10a.
- d. Delay of repair for pumps will be allowed if:
 1. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and
 2. Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.
- e. 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.
- f. When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

[45CSR16, 40 CFR § 60.482-9a, 45CSR13: R13-2334, 8.1.6.]

Standards: Closed vent systems and control devices.

- 8.1.19. a. Owners or operators of closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VVa shall comply with the provisions of 40 CFR § 60.482-10a.
- b. Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.
- c. Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816°C.
- d. Flares used to comply with 40 CFR Part 60 Subpart VVa shall comply with the requirements of 40 CFR § 60.18.
- e. Owners or operators of control devices used to comply with the provisions of 40 CFR Part 60 Subpart VVa shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.
- f. Except as provided in 40 CFR §§ 60.482-10a (i) through (k), each closed vent system shall be inspected according to the procedures and schedule specified in 40 CFR §§ 60.482-10a (f) (1) and (2).
 1. If the vapor collection system or closed vent system is constructed of hard-piping, the permittee shall comply with the requirements specified in 40 CFR §§ 60.482-10a (f)(1)(i) and (ii):
 - i. Conduct an initial inspection according to the procedures in 40 CFR § 60.485a (b); and

- ii. Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.
- 2. If the vapor collection system or closed vent system is constructed of ductwork, the permittee shall:
 - i. Conduct an initial inspection according to the procedures in 40 CFR § 60.485a (b); and
 - ii. Conduct annual inspections according to the procedures in 40 CFR § 60.485a (b).
- g. Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in 40 CFR § 60.482-10a (h).
 - 1. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.
 - 2. Repair shall be completed no later than 15 calendar days after the leak is detected.
- h. Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the permittee determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.
- i. If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2).
- j. Any parts of the closed vent system that are designated, as described in 40 CFR § 60.482-10a (l)(1), as unsafe to inspect are exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR §§ 60.482-10a (j)(1) and (2):
 - 1. The permittee 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 40 CFR § 60.482-10a (f)(1)(i) or (f)(2); and
 - 2. The permittee has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.
- k. Any parts of the closed vent system that are designated, as described in 40 CFR § 60.482-10a (l)(2), as difficult to inspect are exempt from the inspection requirements of 40 CFR §§ 60.482-10a (f)(1)(i) and (f)(2) if they comply with the requirements specified in 40 CFR §§ 60.482-10a (k)(1) through (3):
 - 1. The permittee determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and
 - 2. The process unit within which the closed vent system is located becomes an affected facility through 40 CFR § 60.14 or 60.15, or the permittee designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and
 - 3. The permittee has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

- l. The permittee shall record the information specified in 40 CFR §§ 60.482-10a (l)(1) through (5).
 1. Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.
 2. Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.
 3. For each inspection during which a leak is detected, a record of the information specified in 40 CFR § 60.486a (c).
 4. For each inspection conducted in accordance with 40 CFR § 60.485a (b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
 5. For each visual inspection conducted in accordance with 40 CFR § 60.482-10a (f)(1)(ii) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.
- m. Closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VVa shall be operated at all times when emissions may be vented to them.

[45CSR16, 40 CFR § 60.482-10a, 45CSR13: R13-2334, 8.1.6.]

- 8.1.20. a. The owner or operator shall 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 owner or operator is required to monitor only those connectors involved in the process change.
- b. Except as allowed in 40 CFR § 60.482-1a (c), 40 CFR § 60.482-10a, or as specified in 40 CFR § 60.482-11a (e), the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in 40 CFR §§ 60.482-11a (a) and (b) (3).
 1. The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, 40 CFR § 60.485a (c).
 2. If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.
 3. The owner or operator shall perform monitoring, subsequent to the initial monitoring required in 40 CFR § 60.482-11a (a), as specified in 40 CFR §§ 60.482-11a (b)(3)(i) through (iii), and shall comply with the requirements of 40 CFR §§ 60.482-11a (b)(3)(iv) and (v). The required period in which monitoring must be conducted shall be determined from 40 CFR §§ 60.482-11a (b)(3)(i) through (iii) using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in 40 CFR §§ 60.482-11a (c).

- i. If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).
 - ii. If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.
 - iii. If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in 40 CFR § 60.482-11a (b)(3)(iii)(A) and either 40 CFR § 60.482-11a (b)(3)(iii)(B) or (b)(3)(iii)(C), as appropriate.
 - A. An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.
 - B. If the percent of leaking connectors calculated from the monitoring results in 40 CFR § 60.482-11a (b)(3)(iii)(A) is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to 40 CFR § 60.482-11a (b)(3), based on the percent of leaking connectors within the total monitored connectors.
 - C. If the percent of leaking connectors calculated from the monitoring results in 40 CFR § 60.482-11a (b)(3)(iii)(A) is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.
 - iv. If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
 - v. The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.
- c. For use in determining the monitoring frequency, as specified in 40 CFR §§ 60.482-11a (a) and (b)(3), the percent leaking connectors as used in 40 CFR §§ 60.482-11a (a) and (b)(3) shall be calculated by using the following equation:

$$\%C_L = C_L / C_t \times 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in 40 CFR §§ 60.482-11a (a) and (b)(3)(i) through (iii).

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in 40 CFR § 60.485a (b).

C_t = Total number of monitored connectors in the process unit or affected facility.

- d. When a leak is detected pursuant to 40 CFR §§ 60.482-11a (a) and (b), it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR § 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.
- e. Any connector that is designated, as described in 40 CFR § 60.486a (f)(1), as an unsafe-to-monitor connector is exempt from the requirements of 40 CFR §§ 60.482-11a (a) and (b) if:
 - 1. The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with 40 CFR §§ 60.482-11a (a) and (b); and
 - 2. The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in 40 CFR § 60.482-11a (d) if a leak is detected.
- f. *Inaccessible, ceramic, or ceramic-lined connectors.*
 - 1. 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 (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of 40 CFR §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in 40 CFR §§ 60.482-11a (f)(1)(i) through (vi), as applicable:
 - i. Buried;
 - ii. Insulated in a manner that prevents access to the connector by a monitor probe;
 - iii. Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
 - iv. 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;
 - v. Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
 - vi. 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.
 - 2. If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

- g. Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

[45CSR16, 40 CFR § 60.482-11a, 45CSR13: R13-2334, 8.1.6.]

- 8.1.21. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in 40 CFR Part 60 Subpart VVa.
- b. Determination of equivalence to the equipment, design, and operational requirements of 40 CFR Part 60 Subpart VVa will be evaluated by the following guidelines:
 - 1. Each permittee applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.
 - 2. The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.
 - 3. The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.
- c. Determination of equivalence to the required work practices in 40 CFR Part 60 Subpart VVa will be evaluated by the following guidelines:
 - 1. Each permittee applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.
 - 2. For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.
 - 3. For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.
 - 4. Each permittee applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.
 - 5. The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in 40 CFR § 60.484a (c)(4).
 - 6. The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

- d. The permittee may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.
- e.
 - 1. After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.
 - 2. After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.
 - 3. Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111 (h) (1) of the CAA.
- f.
 - 1. Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of 40 CFR Part 60 Subpart VVa.
 - 2. The Administrator will make an equivalence determination according to the provisions of 40 CFR §§ 60.484a (b), (c), (d), and (e).

[45CSR16, 40 CFR § 60.484a, 45CSR13: R13-2334, 8.1.6.]

8.2. Monitoring Requirements

- 8.2.1. **Reporting, Recording, Tracking, Repairing and Re-monitoring Leaks of Valves and Pumps.** The permittee shall record, track, repair and re-monitor all leaks in excess of the internal leak definitions.
[45CSR13: Permit R13-2334, 8.2.1., 45CSR§30-12.7]

8.2.2. LDAR Monitoring Frequency

- i. Pumps. The permittee shall monitor pumps on a monthly basis.
- ii. Valves. The permittee shall monitor valves -- other than difficult to monitor or unsafe to monitor valves -- on a quarterly basis.

[45CSR13: Permit R13-2334, 8.2.2., 45CSR§30-12.7]

8.2.3. Calibration/Calibration Drift Assessment

- i. Calibration. The permittee shall conduct all calibrations of LDAR monitoring equipment using methane as the calibration gas, in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21.
- ii. Calibration Drift Assessment. The permittee shall conduct calibration drift assessments of LDAR monitoring equipment at the end of each monitoring shift, at a minimum. The permittee shall conduct the calibration drift assessment using, at a minimum, a 500 ppm calibration gas. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous

calibration, the permittee shall re-monitor all valves that were monitored since the last calibration that had a reading greater than 100 ppm and shall re-monitor all pumps that were monitored since the last calibration that had a reading greater than 500 ppm.

[45CSR13: Permit R13-2334, 8.2.3., 45CSR§30-12.7]

8.2.4. **LDAR Audits.** The permittee shall implement at the facility the Refinery audits set forth in the following paragraphs to ensure compliance with all applicable LDAR requirements. The LDAR audits shall include, but not be limited to, comparative monitoring, records review, tagging, data management, and observation of the LDAR technicians' calibration and monitoring techniques.

- i. Third-Party Audits. The permittee shall retain a contractor(s) to perform a third-party audit of the refinery's LDAR program at least once every four years.
- ii. Internal Audits. The permittee shall conduct internal audits of the LDAR program. An internal audit of the refinery shall be held every four years.
- iii. To ensure that an audit at the refinery occurs every two years, third-party and internal audits shall be separated by two years.
- iv. Alternative. As an alternative to the internal audit, the permittee may elect to retain third-parties to undertake the internal audit, provided that an audit of the facility occurs every two (2) years.

[45CSR13: Permit R13-2334, 8.2.4., 45CSR§30-12.7]

8.2.5. If the results of any of the audits conducted at the facility identify any areas of non-compliance, the permittee shall implement, as soon as practicable, all steps necessary to correct the area(s) of noncompliance, and to prevent, to the extent practicable, a recurrence of the cause of the non-compliance. The permittee shall retain the audit reports generated during the audits and shall maintain a written record of the corrective actions taken at the facility in response to any deficiencies identified in any audits.

[45CSR13: Permit R13-2334, 8.2.4., 45CSR§30-12.7]

8.3. Testing Requirements

- 8.3.1. For affected facilities subject to the standards in 40 CFR §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a, the permit shall determine compliance with the standards according to the test methods and procedures provided in §60.485a.
 - a. In conducting the performance tests required in 40 CFR § 60.8, the permittee shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in 40 CFR § 60.8 (b).
 - b. The permittee shall determine compliance with the standards in 40 CFR §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:
 1. Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of 40 CFR Part 60 Appendix A-7. The following calibration gases shall be used:

- i. Zero air (less than 10 ppm of hydrocarbon in air); and
 - ii. A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the permittee need not calibrate the scales that will not be used during that day's monitoring.
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 40 CFR Part 60 Appendix A-7, 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) (7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration 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 initial calibration value, 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 initial calibration value, 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.
- c. The permittee shall determine compliance with the no-detectable-emission standards in 40 CFR §§ 60.482-2a (e), 60.482-3a (i), 60.482-4a, 60.482-7a (f), and 60.482-10a (e) as follows:
 1. The requirements of 40 CFR § 60.485a (b) shall apply.
 2. Method 21 of 40 CFR Part 60 Appendix A-7 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.
- d. The permittee shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:
 1. Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see 40 CFR § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.
 2. Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

3. Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, 40 CFR §§ 60.485a (d)(1) and (2) shall be used to resolve the disagreement.
- e. The permittee shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:
 1. The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see 40 CFR § 60.17) shall be used to determine the vapor pressures.
 2. The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.
 3. The fluid is a liquid at operating conditions.
- f. Samples used in conjunction with 40 CFR §§ 60.485a (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.
- g. The permittee shall determine compliance with the standards of flares as follows:
 1. Method 22 of 40 CFR Part 60 Appendix A-7 shall be used to determine visible emissions.
 2. A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.
 3. The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m⁴/(MJ-sec) (metric units) = 0.087 ft⁴/(Btu-sec) (English units).

4. The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component “i,” ppm

H_i = net heat of combustion of sample component “i” at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

5. Method 18 of 40 CFR Part 60 Appendix A-6 or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see 40 C.F.R. § 60.17) shall be used to determine the concentration of sample component “i.”
6. ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see 40 CFR § 60.17) shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.
7. Method 2, 2A, 2C, or 2D of 40 CFR Part 60 Appendix A-7, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.
- h. The permittee shall determine compliance with 40 CFR § 60.483-1a or 40 CFR § 60.483-2a as follows:
 1. The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L/V_T) \times 100$$

Where:

$\%V_L$ = Percent leaking valves.
 V_L = Number of valves found leaking.
 V_T = The sum of the total number of valves monitored.

2. The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
3. The number of valves leaking shall include valves for which repair has been delayed.
4. Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
5. If the process unit has been subdivided in accordance with 40 CFR § 60.482-7a (c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
6. The total number of valves monitored does not include a valve monitored to verify repair.

[45CSR16, 40 CFR § 60.485a, 45CSR13: R13-2334, 8.3.1.]

8.4. Recordkeeping Requirements

- 8.4.1. **Adding New Valves and Pumps.** The permittee shall establish a tracking program for maintenance records (e.g., a Management of Change program) to ensure that valves and pumps added to the facility during maintenance and construction are integrated into the LDAR program.

[45CSR13: Permit R13-2334, 8.4.1., 45CSR§30-12.7]

8.4.2. When a leak is detected, the following requirements apply:

- i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
- ii. The identification on a valve may be removed after it has been monitored for 2 successive months and no leak has been detected during those 2 months.
- iii. The identification on equipment, except on a valve, may be removed after it has been repaired.
[40 CFR § 60.486a(b), 45CSR13: Permit R13-2334, 8.4.2., 45CSR§30-12.7]

8.4.3. When a leak has been detected, the following information shall be recorded in a log and 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 10,000” if the maximum instrument reading measured after each repair attempt is equal to or greater than 10,000 ppm.
- v. “Repair delayed” and 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.

[40 CFR § 60.486a(c), 45CSR13: Permit R13-2334, 8.4.3., 45CSR§30-12.7]

8.4.4. The following information shall be recorded in a log that is kept in a readily accessible location:

- i. A list of identification numbers.
- ii. A list of identification numbers for equipment that are designated for no detectable emissions. This list shall be signed by the owner or operator.
- iii. A list of equipment identification numbers for pressure relief valves.
- iv. The dates of each compliance test.
- v. The background level measured during each compliance test.

- vi. The maximum instrument reading measured at the equipment during each compliance test.
- vii. A list of identification numbers for equipment in vacuum service.
- viii. A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr, a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

[40 CFR § 60.486a(e), 45CSR13: Permit R13-2334, 8.4.3., 45CSR§30-12.7]

- ix. For all valves and pumps designated as unsafe-to-monitor or difficult-to-monitor:
 - a. A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.
 - b. 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.

[40 CFR § 60.486a(f), 45CSR13: Permit R13-2334, 8.4.4.(xi.), 45CSR§30-12.7]

- 8.4.5. a.
 - 1. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall comply with the recordkeeping requirements of 40 CFR § 60.486a.
 - 2. The permittee of more than one affected facility subject to the provisions of 40 CFR Part 60 Subpart VVa may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
 - 3. The permittee shall record the information specified in 40 CFR §§ 60.486a (a)(3)(i) through (v) for each monitoring event required by 40 CFR §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.
 - i. Monitoring instrument identification.
 - ii. Operator identification.
 - iii. Equipment identification.
 - iv. Date of monitoring.
 - v. Instrument reading.
- b. When each leak is detected as specified in 40 CFR §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:
 - 1. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

2. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7a (c) and no leak has been detected during those 2 months.
 3. The identification on a connector may be removed after it has been monitored as specified in § 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
 4. The identification on equipment, except on a valve or connector, may be removed after it has been repaired.
- c. When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall 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, except when indications of liquids dripping from a pump are designated as a leak.
 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. Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.
 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 permittee (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.
- d. The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10a shall be recorded and kept in a readily accessible location:
1. Detailed schematics, design specifications, and piping and instrumentation diagrams.
 2. The dates and descriptions of any changes in the design specifications.
 3. A description of the parameter or parameters monitored, as required in § 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

4. Periods when the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
5. Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.
- e. The following information pertaining to all equipment subject to the requirements in §§ 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:
 1. A list of identification numbers for equipment subject to the requirements of 40 CFR Part 60 Subpart VVa.
 2.
 - i. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR §§ 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
 - ii. The designation of equipment as subject to the requirements of § 60.482-2a(e), § 60.482-3a(i), or § 60.482-7a(f) shall be signed by the permittee. Alternatively, the permittee may establish a mechanism with their permitting authority that satisfies this requirement.
 3. A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4a.
 4.
 - i. The dates of each compliance test as required in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
 - ii. The background level measured during each compliance test.
 - iii. The maximum instrument reading measured at the equipment during each compliance test.
 5. A list of identification numbers for equipment in vacuum service.
 6. A list of identification numbers for equipment that the permittee designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
 7. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
 8. Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and § 60.485a(b).
 - i. Date of calibration and initials of operator performing the calibration.
 - ii. Calibration gas cylinder identification, certification date, and certified concentration.
 - iii. Instrument scale(s) used.

- iv. 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 of this part.
 - v. Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
 - vi. If the permittee makes their own calibration gas, a description of the procedure used.
- 9. The connector monitoring schedule for each process unit as specified in § 60.482-11a (b)(3) (v).
- 10. Records of each release from a pressure relief device subject to § 60.482-4a.
- f. The following information pertaining to all valves subject to the requirements of 40 CFR §§ 60.482-7a (g) and (h), all pumps subject to the requirements of 40 CFR § 60.482-2a (g), and all connectors subject to the requirements of 40 CFR § 60.482-11a (e) shall be recorded in a log that is kept in a readily accessible location:
 - 1. 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.
 - 2. 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.
- g. The following information shall be recorded for valves complying with 40 CFR § 60.483-2a:
 - 1. A schedule of monitoring.
 - 2. The percent of valves found leaking during each monitoring period.
- h. The following information shall be recorded in a log that is kept in a readily accessible location:
 - 1. Design criterion required in 40 CFR §§ 60.482-2a (d)(5) and 60.482-3a (e)(2) and explanation of the design criterion; and
 - 2. Any changes to this criterion and the reasons for the changes.
- i. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR § 60.480a (d):
 - 1. An analysis demonstrating the design capacity of the affected facility,
 - 2. A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
 - 3. An analysis demonstrating that equipment is not in VOC service.

- j. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.
- k. The provisions of 40 CFR §§ 60.7(b) and (d) do not apply to affected facilities subject to 40 CFR Part 40 Subpart VVa.

[45CSR16, 40 CFR § 60.486a, 45CSR13: R13-2334, 8.4.5.]

8.5. Reporting Requirements

8.5.1. Electronic Monitoring, Storing, and Reporting of LDAR Data

- i. Electronic Storing and Reporting of LDAR Data. The facility will maintain an electronic database (e.g., EXCEL spreadsheet) for storing and reporting LDAR data. The electronic database shall include data identifying the date and time of the monitored event, and the operator and instrument used in the monitored event.
- ii. Electronic Data Collection During LDAR Monitoring and Transfer Thereafter. The permittee shall use data loggers and/or electronic data collection devices during all LDAR monitoring. The permittee, or its designated contractor, shall use its/their best efforts to transfer, by the end of the next business day, electronic data from electronic data logging devices to the electronic database listed above. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp. The permittee may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken), and shall record, at a minimum, the identification of the technician undertaking the monitoring, the date, and the identification of the monitoring equipment. The permittee shall use its best efforts to transfer any manually recorded monitoring data to the electronic database within seven days of monitoring.

[45CSR13: Permit R13-2334, 8.5.1., 45CSR§30-12.7]

- 8.5.2. **QA/QC of LDAR Data** - The permittee shall ensure that monitoring data provided to the permittee by its contractors is reviewed for QA/QC before the contractor submits the data to the permittee. At least once per calendar quarter, the permittee shall perform QA/QC of the contractor's monitoring data which shall include, but not be limited to, number of components monitored per technician, time between monitoring events, and abnormal data patterns.

[45CSR13: Permit R13-2334, 8.5.2., 45CSR§30-12.7]

- 8.5.3. The permittee shall submit semiannual reports to the Administrator beginning six months after the initial startup date. All semiannual reports shall include the following information:

- i. Process unit identification.
- ii. For each month during the semiannual reporting period,
 - a. Number of valves for which leaks were detected.
 - b. Number of valves for which leaks were not repaired.
 - c. Number of pumps for which leaks were detected.

- d. Number of pumps for which leaks were not repaired.
 - e. Number of compressors for which leaks were detected.
 - f. Number of compressors for which leaks were not repaired.
 - g. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.
- iv. Revisions to items reported in initial report if changes have occurred since the initial report or subsequent revisions to the initial report.

[40 CFR § 60.487a(c), 45CSR13: Permit R13-2334, 8.5.3., 45CSR§30-12.7]

- 8.5.4. a. Each permittee subject to the provisions of 40 CFR Part 60 Subpart VVa shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.
- b. The initial semiannual report to the Administrator shall include the following information:
- 1. Process unit identification.
 - 2. Number of valves subject to the requirements of 40 CFR § 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of 40 CFR § 60.482-7a (f).
 - 3. Number of pumps subject to the requirements of 40 CFR § 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of 40 CFR § 60.482-2a (e) and those pumps complying with 40 CFR § 60.482-2a (f).
 - 4. Number of compressors subject to the requirements of 40 CFR § 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of 40 CFR § 60.482-3a (i) and those compressors complying with 40 CFR § 60.482-3a (h).
 - 5. Number of connectors subject to the requirements of 40 CFR § 60.482-11a.
- c. All semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR § 60.486a:
- 1. Process unit identification.
 - 2. For each month during the semiannual reporting period,
 - i. Number of valves for which leaks were detected as described in 40 CFR § 60.482-7a (b) or § 60.483-2a,
 - ii. Number of valves for which leaks were not repaired as required in 40 CFR § 60.482-7a (d)(1),

- iii. Number of pumps for which leaks were detected as described in 40 CFR § 60.482-2a (b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
 - iv. Number of pumps for which leaks were not repaired as required in 40 CFR §§ 60.482-2a(c)(1) and (d)(6),
 - v. Number of compressors for which leaks were detected as described in 40 CFR § 60.482-3a (f),
 - vi. Number of compressors for which leaks were not repaired as required in 40 CFR § 60.482-3a (g) (1),
 - vii. Number of connectors for which leaks were detected as described in 40 CFR § 60.482-11a (b)
 - viii. Number of connectors for which leaks were not repaired as required in 40 CFR § 60.482-11a (d), and
 - ix. [Reserved]
 - x. [Reserved]
 - xi. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
- 3. Dates of process unit shutdowns which occurred within the semiannual reporting period.
 - 4. Revisions to items reported according to 40 CFR § 60.487a (b) if changes have occurred since the initial report or subsequent revisions to the initial report.
- d. The permittee electing to comply with the provisions of 40 CFR §§ 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.
 - e. The permittee shall report the results of all performance tests in accordance with 40 CFR § 60.8 of the General Provisions. The provisions of 40 CFR § 60.8 (d) do not apply to affected facilities subject to the provisions of 40 CFR Part 60 Subpart VVa except that the permittee must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.
 - f. The requirements of 40 CFR §§ 60.487a (a) through (c) remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of 40 CFR §§ 60.487a (a) through (c), provided that they comply with the requirements established by the state.
- [45CSR13: R13-2334, 8.5.4., 45CSR16, 40 CFR § 60.487a]**

8.6. Compliance Plan

- 8.6.1. None.

9.0 Equipment Leaks Requirements [VOC Emissions from Petroleum Refinery Wastewater Systems - 40 CFR Part 60 Subpart QQQ]

9.1. Limitations and Standards

- 9.1.1. a. Each owner or operator subject to the provisions of this subpart shall comply with the requirements of 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.
- b. Compliance with 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.696.
- ~~e.~~—1. Stormwater sewer systems are not subject to the requirements of this subpart.
2. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.
3. Non-contact cooling water systems are not subject to the requirements of this subpart.
4. An owner or operator shall demonstrate compliance with the exclusions in paragraphs c.1., 2., and 3. of this section as provided in 40 CFR § 60.697 (h), (i), and (j).

[40 CFR § 60.692-1(a), (b), and (d), 45CSR16, 45CSR13: Permit R13-2334, 9.1.1.]

9.1.2. Individual drain systems.

- a. 1. Each drain shall be equipped with water seal controls.
2. Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.
3. Each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.
4. Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in 40 CFR § 60.692-6.
- b. 1. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.
2. 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.
3. Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

4. If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in 40 CFR § 60.692-6.
- c.
 1. 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.
 2. The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.
 3. Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in 40 CFR § 60.692-6.
- d. Except as provided in paragraph e. of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987, shall be exempt from the provisions of this section.
- e. Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

[40 CFR § 60.692-2, 45CSR16, 45CSR13: Permit R13-2334, 9.1.2.]

9.1.3. Oil-water separators.

- a. Each oil-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 following specifications, except as provided in paragraph c. of this section or in 40 CFR § 60.693-2.
 1. The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.
 2. The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.
 3. If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.
 4. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.
 5. When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.
- b. Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements

in paragraph a. of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of 40 CFR § 60.692-5.

- c. Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in 40 CFR §§ 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, Subparts K, Ka, or Kb are not subject to the requirements of this section.
- d. Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of 40 CFR Part 60, Subpart QQQ. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph a. of this section.
- e. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph a. of this section, and not paragraph b. of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

[40 CFR § 60.692-3 (a), (b), (d), (e), and (f), 45CSR16, 45CSR13: Permit R13-2334, 9.1.3.]

9.1.4. Alternative standards for oil-water separators.

- a. An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.
 - 1. Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.
 - i. The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.
 - A. A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.
 - B. The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.
 - C. The total gap area between the primary seal and the separator wall shall not exceed 67 cm²/m (3.2 in.²/ft) of separator wall perimeter.
 - ii. The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.
 - A. The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

- B. The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm²/m (0.32 in.²/ft) of separator wall perimeter.
- iii. The maximum gap width and total gap area shall be determined by the methods and procedures specified in 40 CFR § 60.696(d).
 - A. Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.
 - B. Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.
- iv. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs a.1.i. and ii. of this section.
- 2. Except as provided in paragraph a.4. of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.
- 3. The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).
- 4. The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.
- 5.
 - i. Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.
 - ii. When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.
- b. An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph a. of this section.
- c. For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of 40 CFR § 60.692-3(a) shall be installed.
- d. Except as provided in paragraph c. of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of 40 CFR §§ 60.692-3 or 60.694 applicable to the same facilities.

[40 CFR § 60.693-2, 45CSR 16, 45CSR13: Permit R13-2334, 9.1.4.]

9.1.5. Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of 40 CFR §§ 60.692-2 and 60.692-3.

[40 CFR § 60.692-4, 45CSR16, 45CSR13: Permit R13-2334, 9.1.5.]

9.1.6. Closed vent systems and control devices.

- a. Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.
- b. Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.
- c.
 1. Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR § 60.696.
 2. Closed vent systems shall be purged to direct vapor to the control device.
 3. A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.
 4. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.
 5. When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR § 60.692-6.

[40 CFR §§ 60.692-5(b), (d), and (e), 45CSR16, 45CSR13: Permit R13-2334, 9.1.6.]

9.1.7. Delay of repair.

- a. 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.
- b. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

[40 CFR § 60.692-6, 45CSR16, 45CSR13: Permit R13-2334, 9.1.7.]

9.2. Monitoring Requirements

- 9.2.1. Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

- a. Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.

[40 CFR § 60.695(a)(3)(ii), 45CSR16, 45CSR13: Permit R13-2334, 9.2.1.]

9.3. Testing Requirements

- 9.3.1. Before using any equipment installed in compliance with the requirements of 40 CFR § 60.692-2, § 60.692-3, § 60.692-4, § 60.692-5, or § 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.

[40 CFR § 60.696(a), 45CSR16, 45CSR13: Permit R13-2334, 9.3.1.]

- 9.3.2. The owner or operator of each source that is equipped with a closed vent system and control device as required in 40 CFR § 60.692-5 (other than a flare) is exempt from § 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

- a. Zero air (less than 10 ppm of hydrocarbon in air), and
- b. A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

[40 CFR § 60.696(b), 45CSR16, 45CSR13: Permit R13-2334, 9.3.2.]

9.4. Recordkeeping Requirements

- 9.4.1. Each owner or operator of a facility subject to the provisions of this subpart shall comply with the record keeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.

[40 CFR § 60.697(a), 45CSR16, 45CSR13: Permit R13-2334, 9.4.1.]

- 9.4.2. a. For individual drain systems subject to 40 CFR § 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

b. For junction boxes subject to 40 § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

c. For sewer lines subject to 40 CFR §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(b), 45CSR16, 45CSR13: Permit R13-2334, 9.4.2.]

9.4.3. For oil-water separators subject to 40 CFR § 60.692-3, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-3(a) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(c), 45CSR16, 45CSR13: Permit R13-2334, 9.4.3.]

9.4.4. For closed vent systems subject to 40 CFR § 60.692-5 and completely closed drain systems subject to 40 CFR § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-5(e) during which detectable emissions are measured, or a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(d), 45CSR16, 45CSR13: Permit R13-2334, 9.4.4.]

9.4.5. a. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

b. The reason for the delay as specified in 40 CFR § 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

c. The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

d. The date of successful repair or corrective action shall be recorded.

[40 CFR § 60.697(e), 45CSR16, 45CSR13: Permit R13-2334, 9.4.5.]

9.4.6. a. A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

b. The following information pertaining to the design specifications shall be kept.

i. Detailed schematics, and piping and instrumentation diagrams.

ii. The dates and descriptions of any changes in the design specifications.

c. The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with

a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

- ii. For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.
- iii. Dates of startup and shutdown of the closed vent system and control devices required in 40 CFR § 60.692 shall be recorded and kept for 2 years after the information is recorded.
- iv. The dates of each measurement of detectable emissions required in 40 CFR §§ 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.
- v. The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.
- vi. The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.
- vii. Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

[40 CFR § 60.697(f), 45CSR16, 45CSR13: Permit R13-2334, 9.4.6.]

- 9.4.7. For stormwater sewer systems subject to the exclusion in 40 CFR § 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

[40 CFR § 60.697(h), 45CSR16, 45CSR13: Permit R13-2334, 9.4.7.]

- 9.4.8. For ancillary equipment subject to the exclusion in 40 CFR § 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

[40 CFR § 60.697(i), 45CSR16, 45CSR13: Permit R13-2334, 9.4.8.]

9.4.9. For oil-water separators subject to 40 CFR § 60.693-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.693-2(a)(1)(iii)(A) and (B); and shall be maintained for the time periods specified in paragraphs a. and b. below.

- a. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.
 - b. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(B), two years after the information is recorded.
- [40 CFR § 60.697(k), 45CSR16, 45CSR13: Permit R13-2334, 9.4.9.]**

9.5. Reporting Requirements

9.5.1. Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.

[40 CFR § 60.698(b)(1), 45CSR16, 45CSR13: Permit R13-2334, 9.5.1.]

9.5.2. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.

[40 CFR § 60.698(c), 45CSR16, 45CSR13: Permit R13-2334, 9.5.2.]

9.5.3. As applicable, a report shall be submitted semiannually to the Administrator that indicates:

Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in § 60.695(a)(3)(ii).

[40 CFR §§ 60.698(d)(3) and (d)(3)(ii), 45CSR16, 45CSR13: Permit R13-2334, 9.5.3.]

9.5.4. If compliance with the provisions of this subpart is delayed pursuant to 40 CFR § 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.

[40 CFR § 60.698(e), 45CSR16, 45CSR13: Permit R13-2334, 9.5.4.]

9.6. Compliance Plan

9.6.1. None.

10.0 Benzene Waste Operations Requirements from 40 CFR Part 61 Subpart FF

HAPs Emission Standards. The permitted facility shall comply with all applicable provisions of 45CSR34, which, by incorporation, subjects the facility to the provisions of 40 CFR 61 Subpart FF - National Emission Standard for Benzene Waste Operations, provided, however, that compliance with any more stringent limitation set forth under Conditions 5.1.6., 6.1.2. and 7.1.1. of this permit shall also be demonstrated.

[45CSR13: Permit R13-2334, Section 10.0.]

10.1. Limitations and Standards

10.1.1. An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of 40 CFR § 61.342 (b) and (c). The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

- a. Wastes that are exempted from control under 40 C.F.R. §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
- b. The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.
- c. Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of 40 C.F.R. §§ 61.342(c) through (h). If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.
- d. The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in 40 C.F.R. § 61.355(c)(1)(i) (A) through (C).

[40 CFR § 61.342(a), 45CSR34, 45CSR13: Permit R13-2334, 10.1.1.]

10.2. Monitoring Requirements

10.2.1. Compliance with 40 CFR part 61 subpart FF will be determined by review of facility records and results from tests and inspections using methods and procedures specified in Sections 10.3.1. through 10.3.3. of this permit.

[40 CFR § 61.342(g), 45CSR34, 45CSR13: Permit R13-2334, 10.2.1.]

10.3. Testing Requirements

10.3.1. An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

- a. For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in 40 CFR § 61.342(a), the owner or operator shall:
 1. Determine the annual waste quantity for each waste stream using the procedures specified in Section 10.3.2. of this permit.
 2. Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in Section 10.3.3. of this permit.
 3. Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.
- b. Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to Section 10.3.2.b. of this permit.
- c. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:
 1. Comply with the record keeping requirements of 40 CFR § 61.356 and reporting requirements of 40 CFR § 61.357; and
 2. Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.
- d. The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in Section 10.3.2.b. of this permit, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with Sections 10.3.1. through 10.3.3. of this permit. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

[40 CFR § 61.355(a), 45CSR34, 45CSR13: Permit R13-2334, 10.3.1.]

10.3.2. For purposes of the calculation required by Section 10.3.1. of this permit, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in Sections 10.3.2.a. and b. of this permit, by one of the methods given in Sections 10.3.2. c. through e. of this permit.

- a. The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

- b. The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in Section 10.3.1.a.3. of this permit for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under 40 CFR § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.
- c. Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility.
- d. Use the maximum design capacity of the waste management unit; or
- e. Use measurements that are representative of maximum waste generation rates.

[40 CFR § 61.355(b), 45CSR34, 45CSR13: Permit R13-2334, 10.3.2.]

10.3.3. For the purposes of the calculation required by 40 CFR §§ 61.355(a), an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in Section 10.3.3.a. of this permit using either of the methods given in Sections 10.3.3.b. and c. of this permit.

- a. The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:
 - 1. The determination shall be made at the point of waste generation except for the specific cases given in Sections 10.3.3.a.1.A and B. of this permit.
 - A. The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.
 - B. The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in Sections 10.3.3.b. or c. of this permit. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in Section 10.3.1.a.3. of this permit for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.
 - 2. Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.
 - 3. Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination -- to reduce the benzene concentration.

4. The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in Sections 10.3.3.a.1.A. and B. of this permit.
5. For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.
- b. *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under Section 10.3.3.c. of this permit shall be used to resolve the disagreement.
- c. Measurements of the benzene concentration in the waste stream in accordance with the procedures listed in 40 CFR § 61.355(c)(3).

[40 CFR § 61.355(c), 45CSR34, 45CSR13: Permit R13-2334, 10.3.3.]

10.4. Recordkeeping Requirements

- 10.4.1. Each owner or operator of a facility subject to the provisions of 40 CFR Part 61, subpart FF shall comply with the following record keeping requirements. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.
[40 CFR § 61.356(a), 45CSR34, 45CSR13: Permit R13-2334, 10.4.1.]
- 10.4.2. Each owner or operator shall maintain records that identify each waste stream at the facility subject to 40 CFR Part 61, subpart FF, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition, the owner or operator shall maintain the following records:
 - a. For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.
 - b. For each waste stream exempt from 40 CFR § 61.342(c)(1) in accordance with 40 CFR § 61.342(c)(3), the records shall include:
 1. All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute, or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with 40 CFR § 61.342(c)(3)(i), or

2. All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with 40 CFR § 61.342(c)(3)(ii).
- c. For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with 40 CFR § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with 40 CFR § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with 40 CFR § 61.355(a)(1)(iii) of this section.

[40 CFR § 61.356(b), 45CSR34, 45CSR13: Permit R13-2334, 10.4.2.]

10.5. Reporting Requirements

- 10.5.1. Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to 40 CFR § 61.342 and is determined by the procedures specified in 40 CFR § 61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:
 - a. Total annual benzene quantity from facility waste determined in accordance with 40 CFR § 61.355(a) of this subpart.
 - b. A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.
 - c. For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:
 1. Whether or not the water content of the waste stream is greater than 10 percent;
 2. Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;
 3. Annual waste quantity for the waste stream;
 4. Range of benzene concentrations for the waste stream;
 5. Annual average flow-weighted benzene concentration for the waste stream; and
 6. Annual benzene quantity for the waste stream.

- d. The information required in Sections 10.5.1.a., b., and c. of this Permit should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in 40 CFR § 61.10(a).

[40 CFR § 61.357(a), 45CSR34, 45CSR13: Permit R13-2334, 10.5.1.]

- 10.5.2. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in Section 10.5.1.a. through c. of this permit. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by Section 10.5.1.a. through c. is not changed in the following year, the owner or operator may submit a statement to that effect.

[40 CFR § 61.357(c), 45CSR34, 45CSR13: Permit R13-2334, 10.5.2.]

10.6. Compliance Plan

- 10.6.1. None.

11.0 **Internal Combustion Engines (Emergency Generators and Firewater Pump Engines) Requirements** **[FWPUMP1 and FWPUMP2, [CEG01](#)]**

11.1. **Limitations and Standards**

11.1.1. **What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions? ([For the fire pumps engines identified as FWPUMP1 and FWPUMP2.](#))**

If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d of 40 CFR 63 subpart ZZZZ that apply to you.

You must meet the following requirements, except during periods of startup. During periods of startup you must comply with Condition 11.2.1.b.

- Change oil and filter every 500 hours of operation or annually, whichever comes first; (Sources have the option to utilize an oil analysis program as described in Condition 11.2.1.c. in order to extend the specified oil change requirement.)
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

[45CSR34, 40 CFR §63.6603(a) and Table 2d(~~4-1~~); 45CSR13: Permit R13-2334, 11.1.[1.c](#), [2](#)]

11.1.2. **What are my general requirements for complying with this subpart? ([For the fire pumps engines identified as FWPUMP1 and FWPUMP2.](#))**

- You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.
- At all times you 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. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. 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 §63.6605]

11.1.3. **[The engines for the fire pumps identified as FWPUMP1 and FWPUMP2 shall be operated and maintained in accordance with the following requirements.](#)**

- ~~Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for more than 50 hours per calendar year as described in 40 CFR §§63.6640(f)(1) through (4), for these engines are prohibited. Firepump engines FWPUMP1 and FWPUMP2 shall not operate more than 500 hours each per year. Compliance with this limit shall be based on a rolling 12 month total.~~

Commented [CG23]: Delete this new Section and revert back to original. These fire pumps are not designated as emergency. Instead, these fire pumps meet the RICE MACT requirements for non-emergency engines. This avoids the annual hours limit, resettable hour meter, etc. In addition, the existing 500 hours per year limit should remain.

1. There is no time limit on the use of these emergency stationary engines during emergency situations.
 2. The permittee may operate each emergency stationary engine for the purpose specified in 40 CFR §60.4243(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by the following paragraph counts as part of the 100 hours per calendar year allowed by this paragraph.
 3. Each emergency stationary engine 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.
 4. Each emergency stationary engine 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 the above paragraph. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving, 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.
- b. Each engine shall be equipped with a non-resettable hour meter.
- c. Each engine must use diesel fuel that meets the requirements in Condition 11.1.5. of this permit.

[45CSR34, 40 CFR §§63.6640(f), (f)(1), (f)(2), (f)(4), §63.6625(f), §63.6604(b); 45CSR13: Permit R13-2334, 11.1.1.a., 11.1.1.d. and 11.1.1.e.]

11.1.4. The following conditions and requirements are specific to the engine for generator set identified as COGEN (CEG01):

- a. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for more than 50 hours per calendar year as described in 40 CFR §§60.4211(f)(1) through (3), for the engine are prohibited. Emergency operation/situations is defined when electric power from the local utility is interrupted from the facility.
1. There is no time limit on the use of the emergency stationary engine during emergency situations.
 2. The permittee may operate the emergency stationary engine for the purpose specified in 40 CFR §60.4243(f)(2)(i) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by the following paragraph counts as part of the 100 hours per calendar year allowed by this paragraph.

The emergency stationary engine 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.
 3. The emergency stationary engine 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 the above paragraph. 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, 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.

- b. The generator set shall be equipped with an engine or engine configuration that has been certified by the manufacturer to comply with either 40 CFR §60.4202(a)(2) or 40 CFR Part 60.
- c. The permittee shall operate and maintain the engine of the generator set according to the manufacturer's emission-related written instructions.
- d. The permittee shall only change those emission-related settings of the engine that are permitted by the manufacturer.
- e. The maximum nameplate power output of the engine for each generator set shall not be greater as listed in Table 1.0 of this permit.
- f. The engine shall be equipped with a non-resettable hour meter.
- g. The engine must use diesel fuel that meets the requirements in Condition 11.1.5. of this permit.
- h. The engine for CEG01 shall be a model year 2023 or later.
- i. You must meet the requirements of 40 CFR part 1068, as they apply to you.

[45CSR16; 40 CFR §60.4211(a), §60.4211(f); 45CSR13: Permit R13-2334, 11.1.2.]

- 11.1.5. Diesel fuel used by each engine for the generator set or firewater pump shall have a maximum sulfur content no greater than 15 ppm (ultra-low sulfur diesel) and with either a minimum centane index of 40 or a maximum aromatic content of 35 volume percent. Diesel meeting the specifications of Nonroad diesel under 40 CFR §80.510(b) is equivalent.

[45CSR16; 45CSR34; 40 CFR §60.4207(b), §1090.305 §63.6604(b); 45CSR13: Permit R13-2334, 11.1.3.]

- 11.1.6. The engine for generator set identified as COGEN (CEG01) must comply with the emission standards in 40 CFR §60.4202(a)(2) for all pollutants (i.e., the certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I for all pollutants and the smoke standards as specified in 40 CFR §1039).

[45CSR16; 40 CFR §60.4205(b)]

- 11.1.7. The engine for generator set identified as COGEN (CEG01) must meet the emission standards of 40 CFR §60.4205 over the entire life of the engine.

[45CSR16; 40 CFR §60.4206]

- 11.1.8. The certified engine for generator set identified as COGEN (CEG01) must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR §60.411(g). If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance pursuant to 40 CFR §60.4211(g) as follows:

You 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, you 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 you change emission-related settings in a way that is not permitted by the manufacturer. You 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(c), §60.4211(g) and (g)(3)]

11.2. Monitoring Requirements

11.2.1. What are my monitoring, installation, collection, operation, and maintenance requirements? *(For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)*

- a. If you own or operate an existing non-emergency, non- or black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [45CSR13: Permit R13-2334, 11.1.4.]
- b. If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Table 2d to 40 CFR subpart ZZZZ apply.
- c. If you own or operate a stationary CI engine that is subject to the work, operation or management practices in Condition 11.1.1., you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in Condition 11.1.1. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[45CSR34, 40 CFR §63.6625(e), (e)(3.4), (h), and (i); 45CSR13: Permit R13-2334, 11.1.1.b.]

11.2.2. How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements? *(For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)*

- a. You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in 40 CFR 63 subpart ZZZZ, Table 2d that apply to you according to methods specified in 40 CFR 63 subpart ZZZZ, Table 6 (same as Condition 11.2.1.a.)

Commented [CG24]: Original condition should remain. Fire pumps are designated as non-emergency.

- b. You must report each instance in which you did not meet each emission limitation or operating limitation in 40 CFR 63 part ZZZZ, Table 2d that apply to you. These instances are deviations from the emission and operating limitations in this subpart.

[45CSR34, 40 CFR §§63.6640(a), (b) and Table 6(9)]

- 11.2.3. ~~For the purpose of demonstrating compliance with the hours of operation limit in Condition 11.1.3.a. for Emission Units FWPUMP1 and FWPUMP2 and Condition 11.1.4.a. for Emission Unit CEG01, the permittee shall record the number of hours each engine operated during the calendar month and the reason for such operation. For emergency operations, the permittee must document what is classified as the emergency for each emergency operation. The permittee shall maintain a calendar total of hours operated in non-emergency and emergency situations on a calendar year basis. Such records shall be maintained in accordance with Condition 3.4.2. For the purposes of determining compliance with 11.1.3., the permittee shall monitor and record the number of hours per month that fire water pump engines FWPUMP1 and FWPUMP2 operate.~~
[45CSR13: Permit R13-2334, 11.2.1.]

11.3. Testing Requirements

- 11.3.1. None.

11.4. Recordkeeping Requirements

11.4.1. What records must I keep?

- a. For the fire pumps engines identified as FWPUMP1 and FWPUMP2: If you must comply with the emission and operating limitations, you must keep the records described in paragraphs a.1. through a.4., and b.1.
1. A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).
 2. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.
 3. Records of all required maintenance performed on the air pollution control and monitoring equipment.
 4. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition 11.1.2.b., including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
- b. For the fire pumps engines identified as FWPUMP1 and FWPUMP2 and the generator set engine identified as COGEN (CEG01): The permittee ~~you~~ must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to the permittee's ~~your own~~ maintenance plan for each RICE. ~~if you own or operate any of the following stationary RICE; [45CSR13: Permit R13-2334, 11.2.2.]~~
- ~~1. An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.~~

- c. For the fire pumps engines identified as FWPUMP1 and FWPUMP2: If the stationary RICE does not

meet the standards applicable to non-emergency engines, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

Commented [CG25]: Remove reporting requirement. Fire pumps are non-emergency.

[45CSR34, 40 CFR §§63.6655(a), (e) and (e)(3), (f) and (f)(2); 45CSR13: Permit R13-2334, 11.2.2.]

11.4.2. **In what form and how long must I keep my records?** (For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)

Your records must be in a form suitable and readily available for expeditious review according to 40 CFR §63.10(b)(1). As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[45CSR34, 40 CFR §§63.6660]

11.5. Reporting Requirements

11.5.1. ~~None.~~ For the fire pumps engines identified as FWPUMP1 and FWPUMP2, you must report all deviations as defined in 40 CFR 63 Subpart ZZZZ in the semiannual monitoring report required by condition 3.5.6. You must also report each instance in which you did not meet the requirements in Table 8 to 40 CFR 63 Subpart ZZZZ that apply to you
[45CSR34; 40 CFR §63.6640(c), §63.6650(f)]

Commented [CG26]: Remove new reporting section. No reporting requirements. Engines are less than 300 hp and are non-emergency.

11.5.2. If the engine for generator set identified as COGEN (CEG01) operates for the purpose specified in 40 CFR §60.4211(f)(3)(i), you must submit an annual report according to the following requirements

a. The report must contain the following information:

1. Company name and address where the engine is located.
2. Date of the report and beginning and ending dates of the reporting period.
3. Engine site rating and model year.
4. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
5. 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. 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 this subpart 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. Submit the annual report electronically according to 40 CFR §60.4214(g).

[\[45CSR16; 40 CFR §60.4214\(d\)\]](#)

11.6. Compliance Plan

11.6.1. None.

APPENDIX A

45CSR2 & 45CSR10 Monitoring Plan

Commented [CG27]: An updated plan will be submitted to DEP for incorporation as part of the Title V Renewal.

Ergon - West Virginia, Inc.

9995 Ohio River Blvd, Post Office Box 356
Newell, West Virginia 26050-0356

Ms. Carrie McCumbers
WVDEP—Division of Air Quality
601 57th Street SE
Charleston, West Virginia 25304

RE: Monitoring Plan under 45 CSR 2 and 45 CSR 10

Dear Ms McCumbers:

Ergon West Virginia, Inc. (EWWI) is presenting the following monitoring plan as required under Title 45 of the Code of State Regulations (CSR) Series 2 and Series 10 (45 CSR 2 and 45 CSR10). The allowable emission rates for all of these units have been registered as part of air permit (R13-2334).

Boiler C:

This boiler is permitted to combust a combination of natural gas and refinery fuel gas (RFG) and has a design heat capacity (DHC) less than 100 MMBtu/hr.

Regulation 2

- **Opacity:** The combination of natural gas/RFG combusted within the boiler is very similar to natural gas. There is no probable cause that would indicate that opacity would be generated from the combustion of EWWI's RFG. Since natural gas combustion is exempt from visibility testing, EWWI requests that no visible emission testing be required when combusting RFG.
- **Weight Emission Testing:** Under permit R13-2334, EWWI has monthly and yearly limits on particulate (PM) emissions. EWWI documents PM emissions from Boilers A and B utilizing fuel usage records and regulatory limits. To demonstrate that these units operate will below allowable limits, EWWI proposes the following monitoring plan and request that no stack testing be required for the boilers.

Refinery fuel gas: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that significant particulate emissions from the combustion of EWWI's RFG, which is very similar to natural gas, would be generated.

- **As required under §45-2-8.3.c,** EWWI maintains records of the startup and shutdown of the boiler, and the quantity of fuel gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, this boiler cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boiler. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Boiler A and B:

These boilers combust a combination of natural gas and refinery fuel gas and have DHCs greater than 100 MMBtu/hr, but less than 250MMBtu/hr.

Regulation 2

- Opacity: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that opacity would be generated from the combustion of EWVI's RFG. Since natural gas combustion is exempt from visibility testing, EWVI requests that no visible emission testing be required when combusting RFG.
- Weight Emission Testing: Under permit R13-2334, EWVI has monthly and yearly limits on particulate (PM) emissions. EWVI documents PM emissions from Boilers A and B utilizing fuel usage records and regulatory limits. To demonstrate that these units operate will below allowable limits, EWVI proposes the following monitoring plan and request that no stack testing be required for the boilers.

Refinery fuel gas: RFG combusted within the boilers is very similar to natural gas. There is no probable cause that would indicate that significant particulate emissions from the combustion of EWVI's RFG, which is very similar to natural gas, would be generated.

- As required under §45-2-8.3.c, and §45-2A-7, EWVI maintains records of the startup and shutdown of the boilers, and the quantity of RFG combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, these boilers cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boilers. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Combustion Sources – H101R, H102R, H201, H501R, H500's, H600's, H701, H901

These units are process heaters and combust natural gas/refinery fuel gas combination fuel as their primary fuel. All of these units have DHCs between 10-100 MMBtu/hr, except H201, which has a DHC less than 10 MMBtu/hr.

Regulation 2

- **Opacity:** These heaters meet the requirements set forth in this regulation so therefore visible emission testing is indicated per §45-2-3.2. However, these units are exempt from testing and monitoring requirements since the DHCs of these units are less than 100 MMBtu/hr, per §45-2-8.4.c.
- **Weight Emission Testing:** Heater H201 is exempt from testing, monitoring, recordkeeping and reporting requirements as stipulated in §45-2-11, other than of course those requirements stated within the existing permit. The remaining heaters are less than 100 MMBtu/hr and therefore, are exempt from the periodic testing requirements in §45-2-8.1.a and the monitoring requirements in §45-2-8.2.
- As required in §45-2-8.3.c, and §45-2A-7, EWVI maintains records of the startup and shutdown of the heaters and the quantity of RFG and natural gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10-5.1, these heaters cannot burn fuels with hydrogen sulfide (H₂S) content greater than 0.10 grains per dry standard cubic foot. EWVI has continuous monitors that measure H₂S concentration of the RFG to be combusted in the boilers. Documentation of the monitoring data can be provided upon request. Therefore, per §45-10A-5, EWVI proposes that no requirement for stack testing of SO₂ emissions be required as H₂S is continuously measured.

Combustion Sources-H441, H1101

The DHC for H441 is just over 10 MMBtu/hr and the DHC for H1101 is between 10-100 MMBtu/hr. These two heaters are fired with natural gas only.

Regulation 2

- As per the regulation §45-2-8.4.b and the guidance listed in §452A-3.1.a, since these heaters burn only natural gas, they are exempt from visible emission testing and weight emissions testing requirements.
- As required under §45-2-8.3.c, EWVI maintains records of the startup and shutdown of these heaters, and the quantity of natural gas combusted on a monthly basis.

Regulation 10

- As indicated in §45-10A-10.3, since these units combust only natural gas, they are exempt from the requirements in §45-10-8, which includes testing, monitoring, recordkeeping and reporting.

Manufacturing Process Sources-Main Flare

The flare is an emergency control device for the manufacturing process sources of the entire refinery.

Regulation 2

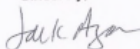
- Regulation 2 does not apply since this regulation only applies to indirect heat exchangers.

Regulation 10

- As indicated in §45-10A-5.2.b, process sources that utilize a flare as a control device are exempt from compliance testing requirements. Also EWWI has a flare gas recovery system on its flare.

If you have any questions or require additional information, please contact me at (304) 387-7046.

Sincerely,



Jack Azar
ESHT Manager

APPENDIX B

Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance

Appendix A of R13-2334 (See 40 CFR §60.7(d))

Summary Report – Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO₂/NO_x/TRS/H₂S/CO/O₂)

Reporting period dates: From _____ to _____

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period¹

<u>Emission Data summary</u>	<u>CMS Performance Summary</u>
1. <u>Duration of excess emissions in reporting period due to:</u>	1. <u>CMS downtime in reporting period due to:</u>
a. <u>Startup/shutdown</u>	a. <u>Monitor equipment malfunctions</u>
b. <u>Control equipment problems</u>	b. <u>Non-Monitor equipment malfunctions</u>
c. <u>Process problems</u>	c. <u>Quality assurance calibration</u>
d. <u>Other known causes</u>	d. <u>Other known causes</u>
e. <u>Unknown causes</u>	e. <u>Unknown causes</u>
2. <u>Total duration of excess emission</u>	2. <u>Total CMS Downtime</u>
3. <u>Total duration of excess emissions × (100) [Total source operating time] %²</u>	3. <u>[Total CMS Downtime] x (100) [Total source operating time] %²</u>

¹For gases, record all times in hours.

²For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process, or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name:

Signature:

Title:

Date:



Tipane, Frederick <frederick.tipane@wv.gov>

Re: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Tipane, Frederick <frederick.tipane@wv.gov>

Tue, Aug 5, 2025 at 1:57 PM

To: Evan Gay <Evan.Gay@ergon.com>

Cc: Greir Merchant <Greir.Merchant@ergon.com>, Caleb Gingerich <caleb.gingerich@trinityconsultants.com>, George Mesing <gmesing@trinityconsultants.com>

You're welcome,

On Tue, Aug 5, 2025 at 1:55 PM Evan Gay <Evan.Gay@ergon.com> wrote:

Perfect. This is very helpful, Fred, and the timeline makes sense.

We are in the process of finalizing our comments on R13-2334AK now and should have those to Ed within the next week. We will also finalize our comments/review of the Title V you provided asap with the understanding that the renewal will be handled separately.

Appreciate it!

Evan

From: Tipane, Frederick <frederick.tipane@wv.gov>**Sent:** Tuesday, August 5, 2025 12:34 PM**To:** Evan Gay <Evan.Gay@ergon.com>**Cc:** Greir Merchant <Greir.Merchant@ergon.com>; Caleb Gingerich <caleb.gingerich@trinityconsultants.com>; George Mesing <gmesing@trinityconsultants.com>**Subject:** Re: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

Hi Evan,

I am doing well. I hope you are too.

In regards to the timing, I need to have the "Draft/Proposed" Significant Modification (SM01) issued before the end of August. Since MM03 will be issued with SM01 (assuming R13-2334AK is issued on time) EPA's "Proposed" period will begin the same time as SM01. In my conversations with Ed Adrews, he indicates that R13-2334AK will be issued sometime within the last couple of weeks in August but in time for me to issue the "DraftProposed" modification permit.

Once the Title V renewal application is received by the DAQ and assigned to the Title V Permitting engineer (I don't know if it will be me), the person for which it is assigned will review the application for administrative completeness based on the "Application Completeness" checklist. Depending on their workload the actual processing of the application will most likely not begin until a later date.

At this point in time I believe it is best to submit your comments for the Pre-Draft R13-2334AK to Ed and any comments you have on the Title V Pre-Draft permit to me independently of the Title V renewal application.

Feel free to contact me with any questions.

Fred

On Tue, Aug 5, 2025 at 12:33 PM Evan Gay <Evan.Gay@ergon.com> wrote:

Good afternoon, Fred –

I hope you're doing well. As our timelines appear to be aligning on several items, I wanted to check in for clarification on the permit issuance schedule. Do you plan to issue MM03 prior to processing our renewal application? We're submitting the application this week, which includes a few additional requested changes to the Title V permit. I'd like to avoid sending multiple rounds of comments if it would be more efficient to consolidate feedback after your review of the renewal package.

I have copied our consultants who are helping us with our review. Thank you for your time and all the work you're putting into this.

Evan

Evan Gay

Sr Environmental Engineer

Corporate Environmental – Projects Team

Ergon, Inc.

M 601-337-1591

P 601-933-3097



From: Tipane, Frederick <frederick.tipane@wv.gov>
Sent: Wednesday, July 30, 2025 2:35 PM
To: Evan Gay <Evan.Gay@ergon.com>; Greir Merchant <Greir.Merchant@ergon.com>
Subject: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

Good afternoon Evan and Greir,

Please find attached for your review the Pre-Draft Permit R30-02900008-2021(SM01, MM03) and Fact Sheet for Ergon West Virginia's Newell Refinery. I have included the Pre-Draft revisions of R13-2334AK and highlighted them in yellow. I will finalize the requirements once R13-2334AK is issued. Since my deadline for issuance is rapidly approaching, I'm requesting that you submit any comments or questions regarding the permit and/or fact sheet to me as soon as possible but no later than August 18, 2025.

Please feel free to contact me with any questions or concerns or if you wish to discuss any issues..

Regards,

Fred

—



Frederick Tipane

Division of Air Quality

601 57th Street, SE

Charleston, WV 25304
(304) 414-1910

frederick.tipane@wv.gov

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Tipane, Frederick <frederick.tipane@wv.gov>

RE: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Evan Gay <Evan.Gay@ergon.com>

Thu, Jul 31, 2025 at 12:31 PM

To: "Tipane, Frederick" <frederick.tipane@wv.gov>, Greir Merchant <Greir.Merchant@ergon.com>

Thank you so much, Fred. I will get started reviewing it asap.

Evan

Evan Gay

Sr Environmental Engineer

Corporate Environmental – Projects Team

Ergon, Inc.

M 601-337-1591

P 601-933-3097



From: Tipane, Frederick <frederick.tipane@wv.gov>

Sent: Wednesday, July 30, 2025 2:35 PM

To: Evan Gay <Evan.Gay@ergon.com>; Greir Merchant <Greir.Merchant@ergon.com>

Subject: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

Good afternoon Evan and Greir,

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finalize the requirements once R13-2334AK is issued. Since my deadline for issuance is rapidly approaching, I'm requesting that you submit any comments or questions regarding the permit and/or fact sheet to me as soon as possible but no later than August 18, 2025.

Please feel free to contact me with any questions or concerns or if you wish to discuss any issues..

Regards,

Fred

--



Frederick Tipane

Division of Air Quality

601 57th Street, SE

Charleston, WV 25304

(304) 414-1910

frederick.tipane@wv.gov

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Tipane, Frederick <frederick.tipane@wv.gov>

Automatic reply: [EXTERNAL]Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Evan Gay <Evan.Gay@ergon.com>

Wed, Jul 30, 2025 at 3:36 PM

To: "Tipane, Frederick" <frederick.tipane@wv.gov>

I am out of the office returning on 7/31. For urgent matters call my cell 601-337-1591 or reach out to Jake Neihaus.

Thanks!

Evan

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Tipane, Frederick <frederick.tipane@wv.gov>

Ergon West Virginia Significant/Minor Modification Pre-Draft permit R30-02900008-20219SM01, MM03)

1 message

Tipane, Frederick <frederick.tipane@wv.gov>

Wed, Jul 30, 2025 at 3:34 PM

To: Evan Gay <Evan.Gay@ergon.com>, Greir Merchant <Greir.Merchant@ergon.com>

Good afternoon Evan and Greir,

Please find attached for your review the Pre-Draft Permit R30-02900008-2021(SM01, MM03) and Fact Sheet for Ergon West Virginia's Newell Refinery. I have included the Pre-Draft revisions of R13-2334AK and highlighted them in yellow. I will finalize the requirements once R13-2334AK is issued. Since my deadline for issuance is rapidly approaching, I'm requesting that you submit any comments or questions regarding the permit and/or fact sheet to me as soon as possible but no later than August 18, 2025.

Please feel free to contact me with any questions or concerns or if you wish to discuss any issues..

Regards,
Fred

--



Frederick Tipane

Division of Air Quality

601 57th Street, SE

Charleston, WV 25304

(304) 414-1910

frederick.tipane@wv.gov

2 attachments**Pre-DPPermit03 R30-02900008-2021(SM01, MM03).docx**
9662K**Pre-DPFactSheet03 R30-02900008-2021(SM01, MM03).doc**
220K

Fact Sheet



Draft/Proposed Significant Modification Permitting Action Under 45CSR30 and Title V of the Clean Air Act

This Fact Sheet serves to address the changes specific to this Significant and Minor Modification, and shall be considered a supplement to the Fact Sheet corresponding with the Title V operating permit issued on February 9, 2021.

Permit Number: **R30-02900008-2021(SM01, MM03)**

Application Received: **August 13, 2024, June 24, 2025**

Plant Identification Number: **03-54-029-00008**

Permittee: **Ergon - West Virginia, Inc.**

Facility Name: **Newell Refinery**

Mailing Address: **9995 Ohio River Blvd, Newell, WV 26050**

Permit Action Number: *SM01, MM03*

Revised: *Draft/Proposed*

Physical Location:	Newell, Hancock County, West Virginia
UTM Coordinates:	531.25 km Easting • 4495.35 km Northing • Zone 17
Directions:	Two miles south of Newell on State Route 2

Facility Description

Ergon - West Virginia, Inc. (EWVI) owns and operates a petroleum refinery (SIC 2911 and NAICS 324110) in Newell, West Virginia. The refinery processes crude oil and produces several petroleum products such as diesel, gasoline, kerosene, and crude oils. The facility has the potential to operate twenty-four (24) hours a day for seven (7) days per week.

Emissions Summary

This modification results in the following emission changes:

Plantwide Emissions Changes (Tons per Year)		
Regulated Pollutants	Potential Emissions	New Potential Emission
NO _x	39.82	245.82
CO	54.85	284.85
SO ₂	6.21	49.21
PM/ PM ₁₀ /PM _{2.5}	7.81	32.01
VOC	9.64	205.61
Total HAPs	1.37	21.49

Title V Program Applicability Basis

With the proposed changes associated with this modification, this facility maintains the potential to emit 284.85 tons per year of Carbon Monoxide, 245.82 tons per year of Nitrogen Oxides, and 205.61 tons per year of Volatile Organic Compounds. Due to this facility's potential to emit over 100 tons per year of a criteria pollutant, Ergon - West Virginia, Inc.'s Newell Refinery 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.

The modification to this facility has been found to be subject to the following applicable rules:

Federal and State:

45CSR2	To Prevent And Control Particulate Air Pollution From Combustion Of Fuel In Indirect Heat Exchangers
45CSR10	Control of Sulfur Dioxide Emissions from Indirect Heat Exchangers.
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
45CSR16	Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60
45CSR30	Requirements For Operating Permits
40 CFR 60 Subpart Ja	Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
40 CFR 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines

State Only:

NA

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

The active permits/consent orders affected by this modification are as follows:

Permit or Consent Order Number	Date of Issuance	Permit Determinations or Amendments That Affect the Permit (<i>if any</i>)
R13-2334AK	August ??? 2025	Still in Pre-Draft

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

The significant modification associated with this revision incorporates the revisions associated with R13-2334AJ Modification Permit for the installation of a cogeneration plant at the Newell Refinery to increase the electrical reliability of supply to the refinery. The cogeneration project consists of a natural gas fired combustion turbine with a duct burner. A “black start” diesel-fire emergency generator will also be installed. The utilization of portable boiler currently at the facility will no longer be authorized 180 days after the initial startup of the combustion turbine. This revision also includes a minor modification associated with R13-2334AK Class I Administrative Update for the incorporation of 40 CFR Subpart KKKK alternative SO₂ monitoring method approved by the Administrator on April 21, 2025, for the combustion turbine when combusting refinery gas that is subject to hydrogen sulfide standard and monitoring requirements of NSPS Subpart Ja. The following are the significant changes to the Title V permit:

Note: In the following discussion, condition numbers reflect the modification revised number unless designated with “CP” which means current permit R30-02900008-2021 (MM02). COA means Citation of Authority.

- 1) **Cover Page** – Added the facility name.
- 2) **Page 1** - Added the facility name. and revised the mailing address as listed in the permit application.
- 3) **Page 2** – Updated the Table of Contents.
- 4) **Title V Boilerplate changes**
 - **Condition 2.1.3.** – Revised resulting from Rule 30 (45CSR30) revisions.
 - **Condition 2.11.4.** – The COA has been corrected.
 - **Condition 2.17.** – Deleted and marked as reserved resulting from Rule 30 revisions.

- **Condition 2.22.1.** – The COA has been updated to remove 45CSR38 which has been repealed.
- **Condition 3.1.6.**– Revised the COA to the current version of the WV Code.
- **Condition 3.3.1.b.** – Added “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.”
- **Condition 3.3.1.** – Revised the COA to the current version of the WV Code.
- **Condition 3.5.3.** – This condition was revised to update the US EPA mailing address.
- **Condition 3.5.4.** – Revised as revised in Rule 30.
- **Condition 3.5.7.** – Deleted and marked as reserved resulting from Rule 30 revisions.
- **Condition 3.5.8.a.1.** – Deleted and marked as reserved resulting from Rule 30 revisions.
- **Condition 3.5.8.a.2.** – Revised as revised in Rule 30.

5) Section 1.1. - Emission Units Table

- Revised Emission Unit 004-01’s (Emission Point ID H-500S) the description and corrected the “Year Installed/Modified” date as revised in R13-2334AK.
- Revised Emission Unit 004-02’s (Emission Point ID H-600S) the description as revised in R13-2334AK.
- Added Emission Units EPN-01 and EPN-03 which had previously been omitted.
- Added the new emission Units TDB01, CCT01, and CEG01.

6) Section 1.2. - Active R13, R14, and R19 Permits Table - Updated R13-2334AI to R13-2334AK and updated the date of issue.

7) Section 3.0.

- Condition 3.1.11. – Revised the COA.
- Condition 3.1.12. – Replaced R13-2334AIF with R13-2334AK.
- Condition 3.7.2.i. – Added “YYYY” to the 40 CFR Part 63 Subpart list for non-applicable permit shield.

8) Section 4.0.

Changes related to R13-2334AJ and SM01

- Section Title – Added “Process” in front of Heaters and added “Combustion Turbine w/ Duct Burner.”
- The R13-2334AJ Modification Permit was issued for the installation of a cogeneration plant at the Newell Refinery to increase the electrical reliability of supply to the refinery. The Cogeneration project consists of a natural gas fired combustion turbine and duct burner. Also, the utilization of

portable boiler under the permit will no longer be authorized 180 days after the initial startup of the combustion turbine. In addition to adding the requirements for the forementioned revisions, the R13 permit writer realized the conditions in Section 4 of R13-2334AI did not contain any level of reasonable organization of flow. R13-2334AI also viewed all the process heaters at the refinery as “fuel burning units” which was in error when the applicable regulatory rules definitions of “fuel burning unit,” “indirect heat exchanger,” and “process heater” are applied correctly to each emission unit (see definitions in 45CSR2, 45CSR10 40 CFR Part 60 Subparts Dc, J and Ja). Therefore, the R13 permit writer restructured most of the conditions contained in Section 4 of R13-2334AJ including the deletion of the table that contained the applicable regulatory rules and the permit condition location of the applicable requirements. In subsection 4.1 of R13-2334AJ each emission unit (EU) is listed in a separate permit condition that describes the type of EU (e.g., process heater, etc.), the applicable rule(s) and the applicable requirements to each EU. In some instances, where there is more than one EU of the same type with the same requirements, they have been included in one permit condition.

This restructuring of Section 4 in R13-2334AJ has been carried over to Section 4 of the Title V permit. Due to this R13 restructuring and changes to existing permit conditions most of all the existing Title V permit conditions have been revised. Many of the existing conditions in Title V permit are no longer applicable or have been relocated, some of which have been streamlined, with the appropriate revised conditions. Therefore, these existing conditions have been deleted in this modification. The Section 4.0 table has also been deleted. Except for the streamlining discussion and the Rule 2 and 10 changes, since this section has undertaken so many revisions the individual revisions will not be discussed. The revisions are evident in that the deletions appear with a “~~strikethrough~~” and in red text while the additions appear in blue text and are underlined.

The following conditions contain Streamlined requirements:

- Condition 4.1.1. – The Boilers A and B 45CSR2 Rule 2 PM limits are less stringent than the R13-2334AJ limits and therefore they have been streamlined with condition 4.1.1.c. Likewise, by meeting the requirement in 4.1.1.e. which refers to condition 4.1.17. for refinery fuel gas hydrogen sulfide fuel requirements, the lb/hr limits in 45CSR§10-3.1.5. and CO-SIP-95-1 Condition V.3 which are less stringent will be met and therefore they have been streamlined with 4.1.1.e.
- Condition 4.1.3. – The Boiler C Rule 2 PM limit is less stringent than the R13-2334AJ limit and therefore has been streamlined with condition 4.1.3.c. Likewise, by meeting the requirement in 4.1.3.e. which refers to condition 4.1.17. for refinery fuel gas hydrogen sulfide fuel requirements, the lb/hr limits in 45CSR§10-3.1.5. which are less stringent will be met and therefore have been streamlined with 4.1.3.e.
- Condition 4.1.4. – This condition contains the new requirements for the Combustion Turbine #1 with duct burner. The duct burner Rule 2 PM limits and Rule 10 SO₂ limits have been streamlined with the more stringent limits in 4.1.4.d. and 4.1.4.g. respectively.
- The R13 permit writer developed a table in the permit evaluation to better illustrate the SO₂ lb/hr limits for the heaters still subject to the SIP SO₂ Consent Order CO-SIP-95-1 (SIP-CO). This table demonstrates that the SIP-CO lb/hr limits are less stringent than the 45CSR10 (Rule 10) and/or the 40 CFR part 60 Subpart J and Ja limits. Therefore, the SIP-CO lb/hr limits have been streamlined with conditions 4.1.7.b., 4.1.10.b., 4.1.11.b., and 4.1.12.b.

The following table was taken from the R13-2334AJ Permit Evaluation:

Table 7 Different in SO ₂ Emission based on Order/Regulatory Limits for H-201, H-501/6 (aka: H-500S), H-6001/5(aka: H-600S) & H-701				
Heater	SO ₂ SIP CO Lt (lb/hr)	Rule 10 Lt (lb/hr)	Subpart J or Ja* Lt (lb/hr)	Existing TPM (lb/hr)
H-201	7.26	0.76	0.21	0.22
H-500S minus H-505R	40.69	5.89	1.56	2.00
H-505R	7.00	1.01	0.27*	
H-600S	33.28	4.82	1.30	1.33
H-701	9.68	1.40	0.38*	0.39

* Denoted the unit is subject to Subpart Ja.

- Condition 4.1.14. – The Heater 1101 Rule 2 PM limit has been streamlined with the more stringent limits in condition 4.1.14.b.
- Condition 4.1.20. – The Portable boiler Rule 2 PM limit and Rule 10 SO₂ limit have been streamlined with the more stringent limits in 4.1.20.
- Condition 4.2.6. – The 40 CFR §60.105(a)(4)(i) span value for the continuous monitoring system for H₂S has been streamlined with the more stringent 40 CFR §60.107a(a)(2)(i) value. Also, Conditions V.3., V.4. and V.5., have been added to the existing compliance language at the end of this condition.
- Condition 4.4.1. – The boilers A and B heat input requirement of CO-SIP-95-1 Condition IV3.A has been streamlined with the fuel usage recordkeeping requirement in this condition.
- Conditions 4.1.3., 4.1.4. and 4.1.8. – These conditions contained requirements from R13-2334AI for the requirements from 45CSR§§2-10.1., 10.2. and 9.1. Since Rule 2 has been revised and no longer contains these requirements, they have been deleted from the permit. These conditions now contain requirements from R13-2334AK.
- Condition 4.1.5. - This condition contained requirements from R13-2334AI for the requirements from 45CSR§10-9.1. Since Rule 10 has been revised and no longer contains these requirements, they have been deleted from the permit. This condition now contains requirements from R13-2334AK

Changes related to R13-2334AK and MM03

- The R13-2334AK Class I Administrative Update was issued to incorporate 40 CFR 60 Subpart KKKK alternative SO₂ monitoring method approved by the Administrator on April 21, 2025. Since the duct burner must comply with the H₂S emission standards of both 40 CFR 60 Subpart Ja and Subpart KKKK, Ergon submitted a request to the Administrator to monitor the more stringent H₂S emissions of Subpart Ja as an alternative to the monitoring for Subpart KKKK when combusting refinery gas. EPA approved the alternative monitoring in a letter dated April 21, 2025. The option for the alternative monitoring was incorporated in R13-2334AK. The revisions in R13-2334AK have been included in the Title V permit in conditions 4.1.4.a.ii., 4.2.12., 4.3.4. introductory text and 4.5.6.a.

9) Section 7.0.

- Condition 7.1.1. – The units in the table were changed from “gallons” to “Mgal” in R13-2334AJ and the numerical values were revised according to the change. To be consistent with the R13 permit, these revisions have been made in this condition.

10) Section 8.0.

- Corrected several topographical errors as corrected in R13-2334AJ. In conditions 8.1.1.a. and c., 8.2.1. and 8.2.4.

11) Section 9.0.

- Condition 9.1.1. - Removed Subsection “c.” numbering as removed in r13-2334AJ.
- Corrected several topographical errors as corrected in R13-2334AJ. In conditions 9.1.2.d., 9.4.4., 9.4.9. and 8.2.4.

12) Section 10.0.

- Corrected several topographical errors as corrected in R13-2334AJ. In condition 10.4.2. introductory text and 10.4.2.b.1.

13) Section 11.0.

- Section Title – Added “Emergency Generator and” in front of “Firewater” and added “CEG01” in the brackets for the emission point IDs.
- Since 40 CFR 63 Subpart ZZZZ is not applicable to the Emergency Generator (See discussion below), “(For the fire pumps engines identified as FWPUMP1 and FWPUMP2.)” has been added to the existing conditions that are applicable to the firewater pump engines in Condition 11.1.1., 11.1.2., 11.2.1., 11.2.2., 11.4.1.a. and 11.4.2.
- Condition 11.1.3. – Revised to add the requirements for 40 CFR 63 Subpart ZZZZ emergency engines as revised in R13-2334AJ.
- Conditions 11.1.4. and 11.1.5. – These conditions were added to include the requirements of 40 CFR 60 Subpart IIII and Permit R13-2334AJ.
- Conditions 11.1.6. 11.1.7. and 11.1.8. – These conditions were added to include the requirements of 40 CFR 60 Subpart IIII.
- Condition 11.2.1.a. – This condition was revised to correct the description for the fire pump engines which are emergency engines. The COA has also been correct to cite 40 CFR §63.6625(e)(3) as opposed to (e)(4). “45CSR13: Permit R13-2334, 11.1.1.b.” has also been added to the COA.
- Condition 11.2.3. – This condition has been revised as revised in R13-2334AJ to also include the emergency generator.
- Condition 11.4.1.
 - 11.4.1.b. has been revised to include the emergency generator engine CEG01 as revised in R13-2334AJ.

- 11.4.1.c. has been added to include the requirements of 40 CFR §63.6655(f) which were previously omitted.
- Condition 11.5.1. - Added the requirements of 40 CFR §63.6640(e) and §63.6650(f) for the fire pump engines which were previously omitted..
- Condition 11.5.2. - Added the requirements of 40 CFR §60.4214(d) for the emergency generator engine CEG01.

14) Appendix B – Added the Appendix A Summary Report form from R13-2334AJ taken from 40 CFR §60.7(d)

Regulatory Applicability

COMBUSTION TURBINE (CT)

The CT with duct burner(DB) is subject to 40 CFR 60 Subpart KKKK – *Standards of Performance for Stationary Combustion Turbines* pursuant to 40 CFR §6.-4305(a) since the CT has a heat input (excluding the duct burner heat input) greater than 10 MMBtu/hr. The CT will be natural gas fired while the DB will be fueled by refinery fuel gas (RFG). Subpart KKKK establishes SO₂ and NO_x emission standards for new combustion turbines. Because the turbine is configured with a generator and a heat recovery steam generator (HRSG) and NO_x emissions are going to be monitored continuously, the combustion turbine is subject to the following standards:

NO_x Standard - No greater than 1.2 lb of NO_x per megawatt-hour (MWh) on a 30-day rolling average basis.

SO₂ Standard - No greater than 0.9 lb of SO₂ per MWh or 0.060 lb of SO₂ per MMBtu on a heat input basis.

Compliance with the NO_x standard will be demonstrated by measuring the actual NO_x emissions with the use of a NO_x continuous emission monitoring system. Due to the form of the standard and configuration of the CT w/HRSG, the system will need to measure the electrical output of the generator and steam output of the HRSG on a continuous basis as well. Without including the output from the HRSG, the NO_x emission rate for the CT w/DB is 0.89 lb/MWh. Accounting for the steam output from the HRSG will increase the margin of compliance for the CT w/HRSG with respect to the NO_x Standard. Therefore, no additional NO_x controls are required by Subpart KKKK.

Compliance with the SO₂ standard will be demonstrated through the use of with a current, valid purchase contract, tariff sheet or transportation contract for the natural gas specifying that the maximum total sulfur content for the natural gas is no greater than 20 grains per 100 cubic feet and/or consuming a gaseous fuel (RFG) that does not exceed 0.060 lb SO₂/MMBtu heat input based

As an option to subpart KKKK SO₂ compliance methods, Ergon has petitioned the Administrator to monitor SO₂ using the monitoring methods for the more stringent H₂S standard in 40 CFR 60 Subpart Ja when consuming RFG. In a letter dated April 21, 2025, EPA granted Ergon's alternative monitoring request.

DUCT BURNER (DB)

The duct burner is subject to the NO_x and SO₂ emissions standards of Subpart KKKK. The duct burner is fueled by RFG firing. When the duct burner is utilized, it is a "fuel gas combustion device" subject to 40 CFR 60 Subpart Ja, a "fuel burning unit" subject to 45CSR2 and 45CSR10. In addition to being subject to

the fuel burning unit requirements of 45CSR§10-2 it is also subject to the requirements for “Combustion of Refinery or Process Gas Steams” in 45CSR§10-5

The following is a summary of the applicable emission standards from these rules and regulations that apply towards the duct burners.

Rule 2: Visible Emission no greater than 10% opacity on a 6-minute average and no greater than 0.09 lb of PM per MMBtu, which equates to a PM rate of 6.98 pounds per hour for this duct burner. Since the R13 PM permit limit is more stringent than Rule 2, the Rule 2 limit will be streamlined with the R13 Limit.

Rule 10: No greater than 3.1 lb of SO₂ per MMBtu, which equates to a SO₂ rate of 240.56 pounds per hour for this duct burner. The refinery fuel gas to be combusted shall not have an H₂S content greater than 50 grains of H₂S per 100 cubic feet of gas. Since the R13 H₂S permit limit converted to SO₂ lb/hr is more stringent than Rule 10, the Rule 10 lb/hr limit will be streamlined with the R13 limit. Compliance with the H₂S limit will be demonstrated using a continuous monitoring system.

Subpart Ja Standard: Fuel gas combustion device shall not combust refinery gas that contains a H₂S content greater than 162 ppmv on a 3-hour rolling average basis and 60 ppmv on a daily 365 day average

The refinery is configured so that the generated refinery gas is mixed with natural gas, which is referred to as “refinery fuel gas” (RFG). The consternation of the H₂S is monitored just downstream once natural gas is mixed with the refinery gas. This stream first supplies the heaters then additional natural gas is injected into the refinery fuel gas header, which dilutes the refinery fuel gas a second time. Then, the refinery fuel gas is used to supply Boilers A and B with fuel. The duct burner is fueled with the RFG just downstream of Boilers A and B.

The facility already uses a continuous H₂S emission monitoring system that has been certified to Performance Specification 7 and maintained in accordance with quality assurance procedures in Appendix F of 40CFR60. This monitoring system is allowed under Subpart Ja and Rule 10 as a means of demonstrating compliance with the applicable standards.

FLUID COOLER

The fluid cooler (CCT01) is not subject to any state or federal regulation that establishes emission standards for cooling towers.

EMERGENCY GENERATOR

The emergency generator engine is aa 1,881 HP compression ignition internal combustion engine that commenced construction after July 11, 2005, and manufactured after April 1, 2006, and is not a fire pump engine. It is subject to the requirements of 40 CFR 60 Subpart IIII. The engine is certified by EPA’s Office of Transportation and Air Quality as a stationary engine compliant with the emissions standards of 40 CFR 60. The engine will comply with the applicable provisions of 40 CFR §60.4211(f) for an emergency engine. This subpart requires the engine to utilized “ultra-low sulfur diesel” fuel and requires that an operating hour meter be installed and maintained. The engine will be in compliance with the requirements of Subpart IIII.

Because the Newell Refinery is an area source of HAPs and the engine is subject to 40 CFR 60 Subpart IIII, the engine meets the requirements of 40 CFR 63 Subpart ZZZZ (RICE MACT) by satisfying the requirements of 40 CFR 60 Subpart IIII.

Non-Applicability Determinations

The following requirements have been determined not to be applicable to the subject facility due to the following:

- 40 CFR 60 Subpart Dc** *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.* The duct burner is subject to 40 CFR 60 Subpart KKKK and therefore pursuant to 40 CFR §60.4305(b) it is exempted from Subpart Dc
- 40 CFR 60 Subpart GG** *Standards of Performance for Stationary Gas Turbines.* The Combustion turbine is subject to 40 CFR 60 Subpart KKKK and therefore pursuant to 40 CFR §60.4305(b) it is exempted from Subpart GG.
- 40 CFR 63 Subpart YYYY** *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.* The Newell Refinery is not a major source of HAP emissions and therefore is not subject to this subpart.
- 40 CFR Part 64** *Compliance Assurance Monitoring.* The combustion turbine with duct burner and the emergency generator engine do not have a pre-control potential to emit any applicable regulated pollution to be classified as a major source. Furthermore, they do not use add-on emission control devices to achieve compliance.

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: (Date of Notice Publication)
Ending Date: (Publication Date PLUS 30 Days)

Point of Contact

All written comments should be addressed to the following individual and office:

Frederick Tipane
West Virginia Department of Environmental Protection
Division of Air Quality
601 57th Street SE
Charleston, WV 25304
304/414-1910
frederick.tipane@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.