Colorado Department of Public Health and Environment

OPERATING PERMIT

Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 1 (West) & Plant 3 (Asphalt Unit)

First Issued: August 1, 2004
Renewed: July 9, 2024

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME:	Commerce City Refinery, Plants 1 and 3	OPERATING PERMIT NUMBER
FACILITY ID:	001- 0003	**96OPAD120**
RENEWED:	July 9, 2024	
EXPIRATION DATE:	July 9, 2029	
MODIFICATIONS:	See Appendix F of Permit	

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:	PLANT SITE LOCATION:
Suncor Energy (U.S.A.), Inc. 5801 Brighton Blvd. Commerce City, CO 80022-3696	Commerce City Refinery, Plants 1 and 3 5801 Brighton Blvd. Commerce City, CO 80022- 3696 Adams County

INFORMATION RELIED UPON

Operating Permit Renewal Application Received:	September 16, 2016
And Additional Information Received:	Various – see Technical Review Document that supports the renewal permit.

Nature of Business: Petroleum Refining
Primary SIC: 2911

RESPONSIBLE OFFICIAL		FACILITY CONTACT PERSON	
Name:	Jeff Krafve	Name:	Bernd Haneke
Title:	VP Commerce City Refinery	Title:	Manager- Environmental and Regulatory
Phone:	(303) 286-2070	Phone	(303) 227-7527

RESPONSIBLE OFFICIAL'S AUTHORIZED REPRESENTATIVE

Name: Vincente DiLuca
Title: Manager, Environmental, Health & Safety
Phone: (720) 827-4114

SUBMITTAL DEADLINES

First Semi-Annual Monitoring Period:	July 9, 2024 – December 31, 2024
Subsequent Semi-Annual Monitoring Periods:	January 1 - June 30, July 1 - December 31
Semi-Annual Monitoring Reports:	Due March 1, 2025 & September 1, 2025 & subs. years
First Annual Compliance Period:	July 9, 2024 – June 30, 2025
Subsequent Annual Compliance Period:	July 1 – June 30
Annual Compliance Certification:	Due on September 1, 2025 and subsequent years

Note that the Semi-Annual Monitoring Report and the Annual Compliance Certification must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 This facility is classified as a petroleum refinery under Standard Industrial Code 2911. Plant 1 is the portion of the heritage Conoco facility located on the west side of Brighton Boulevard (formerly the West Plant) and Plant 3 is the portion of the heritage Conoco facility located on the east side of Brighton Boulevard (formerly the Asphalt Unit). The Plant 1 and 3 facilities form an integrated petroleum refinery producing a wide range of finished petroleum products, including gasoline, jet fuel, diesel fuel, fuel oil, LPG, vacuum residue and sulfur. Processes used at the facility include atmospheric and vacuum distillation, desalting, reforming, catalytic cracking, catalytic polymerization and hydrotreating. The facility processes both sweet and sour crude oils received via pipeline. The No. 1 Crude Unit (Plant 1) has a nominal capacity to process 32,000 barrels per day of crude and the No. 3 Crude Unit (Asphalt Unit, Plant 3) has a nominal capacity to process 38,540 barrels per day. The No. 1 Crude Unit processes sweet (low sulfur crude) and the No. 3 Crude Unit processes sour (high sulfur crude). Finished products primarily leave the refinery via rail and truck loading facilities.

This facility also consists of Plant 2 (formerly the East Plant) which was formerly owned by Colorado Refining Company and is addressed in a separate Title V Operating Permit (95OPAD108). Plant 2 has a nominal capacity of 35,000 barrels per day.

The facility is located at 5801 Brighton Boulevard, Commerce City. The Denver Metro Area is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}) and carbon monoxide. Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as non-attainment for ozone and is part of the 8-hour Ozone Control Area as defined in Regulation No. 7, Part A, Section II.A.1. The 8-hr Ozone Control Area was classified as a serious ozone non-attainment area effective January 27, 2020 and as a severe ozone non-attainment area effective November 7, 2022.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park and Eagle Nest National Wilderness Area, both Federal Class I designated areas, are within 100 kilometers of the plant.

1.2 Until such time as this permit expires or is modified or revoked, the permittee is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 This Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this

Operating Permit and shall survive reissuance. Any requirements that were designated in the Consent Decree (H-01-4430, entered April 30, 2002), First Amendment to the Consent Decree (entered August 8, 2003), Second Amendment to the Consent Decree (entered October 2006) and Compliance Orders on Consent (December 17, 2001 and March 28, 2012), as applicable requirements have been incorporated into this operating permit and shall survive reissuance as applicable requirements. This Operating Permit incorporates the applicable requirements (except as noted in Section II) from the following Colorado Construction Permit(s): 84AD027, 85AD027(1-2), 85AD079, 86AD059, 86AD450, 87AD110, 87AD210, 88AD012, 88AD388, 89AD164, 90AD474, 90AD524, 91AD180 (1, 2 & 4), 88AD240, 96AD881, 90AD053, 91AD726R, 97AD0699, 98AD0896, 99AD0432, 99AD0931, 01AD0363, 01AD0609, 01AD0899, 02AD0326, 02AD0327, 03AD0030, 03AD0031, 03AD0153, 04AD0109, 04AD0110, 04AD0111, 04AD0112, 04AD0113, 04AD0114, 04AD0115, 09AD1351, 09AD1352, 10AD1768, 12AD1825, 12AD1826, 20AD0714 and 20AD0715.

1.4 All conditions in this permit are enforceable by US Environmental Protection Agency, Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II – Condition 12.11 (Regional Haze), Condition 19.11 (Regional Haze), Condition 22.1.1 (Regional Haze), Condition 35.3 (opacity, as referenced throughout this permit), Condition 38.6 (emergency notifications), Condition 38.7 (fenceline monitoring), Condition 38.8 (annual emissions report), Condition 38.9 (quarterly community report) and Condition 38.10 (disseminate continuous emissions monitoring data to public website), Condition 38.11 (disseminate continuous emissions monitoring data to the Division), Condition 38.12 (upgrades to community-based monitors), and Section IV – Conditions as noted.

Note that the Regional Haze Requirements (Conditions 12.11 and 19.11) are state-only enforceable until the requirements adopted by the AQCC on December 17, 2021 into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section IV of this permit. Either electronic or hard copy records are acceptable.

1.6 This Operating Permit incorporates applicable requirements associated with Consent Decree (H-01-443, entered April 30, 2002), the First Amendment to the Consent Decree (entered August 8, 2003), the Second Amendment to the Consent Decree (entered October 2006) and Compliance Orders on Consent (December 17, 2001 and March 28, 2012). To the extent that wording in this Operating Permit differs from the wording in these documents, the wording in the Consent Decree (H-01-4430), the First Amendment to the Consent Decree (entered August 8, 2003), the Second Amendment to the Consent Decree (entered October 2006) and Compliance Orders on Consent (December 17, 2001 and March 28, 2012), is deemed to be the correct wording.

2. Alternative Operating Scenarios

2.1 The permittee shall be allowed to make the following changes to its method of operation without applying for a revision of this permit.

2.1.1 No separate operating scenarios have been specified.

3. Nonattainment Area New Source Review (NANSR) and Prevention of Significant Deterioration (PSD)

3.1 This facility is categorized as a NANSR major stationary source (Potential to Emit of VOC and NO_X >50 tons/year). Future modifications at this facility resulting in a significant net emissions increase (see Regulation No. 3, Part D, Sections II.A.27 and 44) for VOC or NO_X or a modification which is major by itself (Potential to Emit $\geq$ 50 tons/year or either VOC or NO_X) may result in the application of the NANSR review requirements.

3.2 This source is categorized as a PSD major stationary source (Potential to Emit $\geq$ 100 tons/year) for PM, PM_{10}, SO_2, NO_X and CO. Future modifications at this facility resulting in a significant net emissions increase (see Regulation No. 3, Part D, Sections II.A.27 and 44) or a modification that is major by itself (Potential to Emit > 100 tons/yr) for any pollutant listed in Regulation No. 3, Part D, Section II.A.44 for which the area is in attainment or attainment/maintenance may result in the application of the PSD review requirements.

3.3 The following Operating Permit is associated with this facility for purposes of determining applicability of NANSR and PSD review regulations: 95OPAD108 (Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 2 (East))

4. Accidental Release Prevention Program (112(r))

4.1 Based on information provided by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

5. Summary of Emission Units

5.1 The emissions units regulated by this permit are the following:

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
		Petroleum Liquid Storage Tanks		
D-811	APEN exempt[1]	42,000 gallon capacity pressurized propane storage tank		N/A
D-812	APEN exempt[1]	42,000 gallon capacity pressurized propane storage tank		N/A
D-813	APEN exempt[1]	42,000 gallon capacity pressurized propane storage tank		N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
D-814	APEN exempt[1]	42,000 gallon capacity pressurized propane storage tank		N/A
T1	050	81,260 barrel external floating roof gasoline tank	1975	01AD0899
T2	094	120,000 barrel fixed roof, petroleum distillate tank		03AD0031
T3	090	120,000 barrel fixed roof petroleum distillate tank	2/2000	99AD0432
T34	092	90,000 barrel external floating roof gasoline mixtures storage tank	9/2002	01AD0609
T52	141	22,547 barrel external floating roof tank. This tank primarily stores sour water but a layer of diesel is on top of the sour water to minimize volatilization of H_2S.		N/A
T55	028	80,000 barrel external floating roof petroleum feedstock and/or products storage tank	1/2001	99AD0931
T57	107	5,000 barrel fixed roof carbon black storage tank		N/A
T58	065	25,000 barrel external floating roof crude oil storage tank	1957	N/A
T59	108	10,000 barrel fixed roof clarified oil storage tank		N/A
T62	080	47,000 barrel external floating roof Jet 50/kerosene storage tank	1991	90AD474
T64	109	25,118 barrel external floating roof diesel storage tank	1960	N/A
T65	110	25,118 barrel external floating roof diesel storage tank	1960	N/A
T66	111	25,118 barrel external floating roof diesel storage tank	1960	N/A
T67	043	25,119 barrel external floating roof gasoline blend stock storage tank	1961	N/A
T68	112	2,623 barrel fixed roof vacuum resid. storage tank		N/A
T69	113	2,623 barrel fixed roof vacuum resid. storage tank		N/A
T70	049	80,000 barrel external floating roof gasoline blend stock storage tank	1963	N/A
T71	114	80,426 barrel fixed roof resid. storage tank		N/A
T72	115	80,574 barrel external floating roof diesel storage tank	1938	N/A
T74	031	25,000 barrel fixed roof diesel/kerosene storage tank	1969	N/A
T75	056	80,000 barrel external floating roof gasoline storage tank	1969	N/A
T76	116	10,000 barrel fixed roof resid. storage tank		N/A
T77	046	120,000 barrel external floating roof gasoline storage tank	1971	N/A
T78	045	120,000 barrel external floating roof gasoline storage tank	1971	N/A
T80	057	120,667 barrel external floating roof gasoline blending stock storage tank	1971	N/A
T81	APEN exempt[1]	46,824 gallon capacity pressurized butane storage tank		N/A
T82	APEN exempt[1]	31,600 gallon capacity pressurized butane storage tank		N/A
T90	APEN exempt[1]	28,382 gallon capacity pressurized butane storage tank		N/A
T91	APEN exempt[1]	29,382 gallon capacity pressurized butane storage tank		N/A
T92	APEN exempt[1]	28,382 gallon capacity pressurized butane storage tank		N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
T94	015	80,000 barrel jet kerosene fixed roof storage tank	4/1985	85AD027-2
T96	059	20,000 barrel gasoline internal floating roof storage tank	1988	87AD110
T97	066	20,000 barrel gasoline internal floating roof storage tank	1988	87AD110
T105	117	5,141 barrel fixed roof asphalt slop storage tank		N/A
T112	118	15,095 barrel fixed roof asphalt storage tank		N/A
T116	072	25,000 barrel internal floating roof gasoline component storage tank	1988	87AD210
T140	119	16,786 barrel fixed roof heavy oil storage tank		N/A
T142	120	10,346 barrel fixed roof asphalt storage tank		N/A
T144	121	39,481 barrel fixed roof gas oil storage tank		N/A
T145	122	80,574 barrel fixed roof asphalt storage tank		N/A
T146	123	55,954 barrel fixed roof asphalt storage tank		N/A
T147	124	80,574 barrel fixed roof asphalt storage tank		N/A
T182	135	280 barrel fixed roof diesel storage tank		N/A
T191	125	10,346 barrel fixed roof asphalt storage tank		N/A
T192	126	10,346 barrel fixed roof asphalt storage tank		N/A
T193	127	10,317 barrel fixed roof asphalt storage tank		N/A
T194	128	24,985 barrel fixed roof asphalt storage tank		N/A
T400	APEN exempt[1]	8,000 barrel propane/butane mixture pressurized storage tank		N/A
T774	104	120,000 barrel external-floating roof, diesel storage tank		04AD0114
T775	042	120,000 barrel external floating roof crude oil storage tank	1948	98AD0896
T776	061	120,000 barrel external floating roof crude oil storage tank	1948	N/A
T777	105	120,000 barrel external floating roof light straight run (LSR)/naphtha/kerosene storage tank	1972	04AD0115
T778	037	120,000 barrel external floating roof naphtha storage tank. Crude oil is stored in this tank when other crude oil tanks are out of service for inspection or repair.	1971	N/A
T2006	088	55,000 barrel fixed roof asphalt storage tank	4/1997	96AD881
T2010	089	80,000 barrel external floating roof gasoline storage tank	9/1998	97AD0699
T3201	093	120,000 barrel fixed roof petroleum distillate/asphalt storage tank	1/2004	03AD0030
T3801	129	53,138 barrel fixed roof kerosene or heavier petroleum product storage tank		N/A
T7208	070	4,000 barrel internal floating roof organic liquids storage tank. This tank serves the truck rack.		88AD240
	APEN Exempt[2]	Pipeline Receipt Station Sump, 3,000 gallons, underground	April 2016	
		Fired Sources		
H-6	004	Radco Inc. SN SJ502 14.4 MMBtu/hr Vacuum Tower Preheater. This heater serves the No. 1 (Plant 1) Crude Unit, which is nominally rated at 32,000 barrels per day.	1956 Modified 1977 & 1988	N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
H-10	007	Tulsa Heaters Inc. H10/N/A 34.02 MMBtu/hr Re-Run Feed Heater. This heater serves the No. 2 Hydrodesulfurizer (HDS), which is nominally rated at 15,000 barrels per day. The No. 2 HDS treats light straight run (LSR), naphtha and kerosene.	1959	90AD053
H-11	009	K.W. Aldelson SN89379 29.76 MMBtu/hr Vacuum Tower Heater. This heater serves the No. 1 (Plant 1) Crude Unit, which is nominally rated at 32,000 barrels per day.	1960	90AD053
H-13	014	One Radco Inc. S/N 352, refinery fuel gas fired process heater, 6.8 MMBtu/hour, for heating asphalt. This heater serves the No. 3 (Plant 3) Crude Unit (also referred to as the Asphalt Unit), which is nominally rated at 38,540 barrels per day.	1985	85AD027-1
H-16	052	Radco Inc. 6.0 MMBtu/hr Heater. North Oil Heating Furnace, used for asphalt blending and loading.	1966	N/A
H-17	013	One Custom S/N 352 refinery fuel gas fired process heater, 58.4 MMBtu/hour, for heating asphalt. This heater serves the No. 3 (Plant 3) Crude Unit (also referred to as the Asphalt Unit), which is nominally rated at 38,540 barrels per day.	1984	84AD027
H-18	051	Empire 6.0 MMBtu/hr Heater. South Oil Heating Furnace, used for asphalt blending and loading.	1966	N/A
H-19	016	One custom built, Model H-19, S/N SJ-114, refinery fuel gas fired heater, 29.18 MMBtu/hour, for heating of charge to the No. 2 HDS. The No. 2 HDS is nominally rated at 15,000 barrels per day and treats LSR, naphtha and kerosene.	1959 Modified 1991	90AD524
H-20	017	Radco Inc. 14.0 MMBtu/hr Heater. This heater serves the Naphtha Splitter/Stabilizer.	1958	N/A
H-21	APEN Exempt[2]	M. W. Kellog Co., 24 MMBtu/hr, Fluid Catalytic Cracking Unit (FCCU) Air Preheater	1947	N/A
H-22	018	Born Engineering Inc. 59.76 MMBtu/hr FCCU Heater	1971	N/A
H-27	054	Radco Inc. H27/SJ480 76.48 MMBtu/hr Crude Preheater. This heater serves the No. 1 (Plant 1) Crude Unit, which is nominally rated at 32,000 barrels per day.	1974	90AD053
H-28, 29, 30	078	Refinery fuel gas fired heaters: Radco S/N 369, H-28, rated at 35.6 MMBtu/hr; Radco S/N 370, H-29, rated at 35.6 MMBtu/hr; and Radco S/N 368, H-30, rated at 17.4 MMBtu/hr. Total heat input rating: 88.6 MMBtu/hour. These heaters serve the Catalytic Reforming Unit.	2/1989	86AD059
H-31	002	One custom built, Model H-31 refinery gas fuel fired heater, 23.56 MMBtu/hour, for heating of gas-oil charge to the No. 3 HDS. The No. 3 HDS is rated at 25,352 barrels per day.	8/1993	91AD180-1
H-32	003	One custom built, Model H-32 refinery fuel gas fired heater, 37.8 MMBtu/hour, for heating of Fractionator Unit. This heater serves the No. 3 HDS, which is rated at 25,352 barrels per day.	8/1993	91AD180-1

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
H-33	010	One custom built, Model H-33 refinery gas fuel fired heater, 7.680 MMBtu/hour, for heating of asphalt. Equipped with ultra-low NOx burners (ULNB). This heater serves the No. 3 (Plant 3) Crude Unit (also referred to as the Asphalt Unit), which is nominally rated at 38,540 barrels per day.	1993	91AD180-2
H-37	012	One custom built, Model H-37 refinery fuel gas fired heater, 57.24 MMBtu/hour, for heating of asphalt. Equipped with ULNB. This heater serves the No. 3 (Plant 3) Crude Unit (also referred to as the Asphalt Unit), which is nominally rated at 38,540 barrels per day.	1993, modified 4/2021 (installed ULNB)	91AD180-2
H-1716	097	One custom built, Model H-1716 refinery fuel gas fired heater, 57.96 MMBtu/hour for heating gas-oil charge to the Gas Oil HDS (also referred to as the No. 4 HDS)	5/2006	04AD0110
H-1717	098	One custom built, Model H-1717 refinery fuel gas fired heater, 38.64 MMBtu/hr for heating of gas-oil charge to the Gas Oil HDS (also referred to as the No. 4 HDS)	5/2006	04AD0110
H-2101	096	One custom built, Model H-2101 natural gas/PSA reject gas fired steam methane reformer heater, 331 MMBtu/hour, for production of purified H_2 in the Hydrogen Plant.	1/2006	04AD0109
H-2410	137	Tulsa Heaters Inc., Model No. J10-661, S/N VP-24H2410-014, refinery fuel gas fired heater, 51.5 MMBtu/hour for re-boiling in the Gasoline Benzene Reduction (GBR) Unit. Equipped with ultra-low NO_X burners.	5/2012	09AD1351
B-4	019	Henry Vogt Machine Co. Model WSPSN 1986 130.0 MMBtu/hr steam boiler, equipped with ultra-low NO_X burners..	Prior to 1963 Modified 9/2021 (install ULNB)	20AD0714
B-6	021	Zurn Industries Inc. Model 898307 SN10056 111.0 MMBtu/hr steam boiler, equipped with low-NOx burners (LNB).	1971, modified 12/2003 (install LNB)	02AD0326
B-8	023	Zurn Industries Inc. SN 98974 161.0 MMBtu/hr steam boiler, equipped with low-NOx burners	1974, modified 12/2004 (install LNB)	02AD0327
		Process Units		
H-25	100	Sulfur Recovery Units (P101 - SRU #1 – 2-Stage Claus Unit and P102 - SRU #2 – 3 Stage Claus Unit) with Tail Gas Unit (TGU) and TGU Incinerator H-25. Emissions from the SRUs and their associated sulfur pits (SRU #1 (T-98) and SRU #2 (T2005 and T2000)) are routed through the TGU and vented through the TGU incinerator. H-25, custom built refinery fuel gas fired incinerator, rated at 15 MMBtu/hour (pilot).	SRU #1 2/1977 SRU #2 7/1993 H-25 4/2006	04AD0111
P103	025	FCC Regenerator A third stage separator commenced operation in March 2006 to control PM emissions. The regenerator operates in full burn mode, uses palladium combustion promoters and is equipped with a waste heat boiler that provides steam to the refinery.	1971	N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
P104	N/A[3]	Catalytic Reforming Unit		N/A
		Loading Racks		
R101	067	Rail Loading Rack equipped with a Zeeco, Inc. enclosed vapor combustion unit (VCU), Model No. EGF-640	1989 Flare replaced with an enclosed VCU December 2018	88AD012
		Truck Loading Rack (Denver Products Terminal)		
R102	069	Truck Loading Rack and Flare	5/1987	86AD450
F203	162	Truck Loading Rack Drains	5/1987, controls installed December 2017	
SU0001	163	Truck Loading Rack Sump. 8,000 gallon underground horizontal tank, routed to two (2) carbon canisters in series.	December 2017	
		Flares		
F1	073	Plant 1 (Main Plant (MP)) Flare, Steam-Assisted, Equipped with Flare Gas Recovery System	Prior to 1950 Modified (per NSPS Ja) in 2015	N/A
F2	074	Plant 3 (Asphalt Unit (AU)) Flare, Air-Assisted, Equipped with Flare Gas Recovery System	1984 Modified (per NSPS Ja) in 2015	N/A
F3	139	GBR Unit Flare. Zeeco, Model No. QFSC-24/28, Steam-Assisted Flare. S/N 601-Z-1002	4/2012	10AD1768
		Remediation Equipment		
A1	079	Inlet basin and two air strippers for removal of hydrocarbons from contaminated groundwater near Sand Creek – Air Strippers mfctd by R.E. Wright, Model AST, S/N's: 90-ST-729A and 90-ST-729B	7/1990	88AD388
SV1	106[4]	Remediation Service International (RSI), Model No. V3, 4-stroke rich burn combustion engine, rated at 0.60 MMBtu/hr and 50 hp. This unit is used to recover and combust vapors extracted from soil.	10/2007	N/A
		F101 – Asphalt Unit (Plant 3) Wastewater Treatment System		
F101	085	Asphalt Unit (Plant 3) Wastewater Treatment System – CPI Separator and Individual Drain System. The CPI separator is enclosed and vapors vented to a carbon filter. The CPI design capacity is 200 gpm.	10/1992	91AD726R
		F201 – Plant 1 Wastewater Treatment System		
T4501	095	5,768 barrel external floating roof storage tank for sour water and/or wastewater with a layer of floating diesel or slop oil	1/2004	03AD0153

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
		Controlled Sources. The following sources are controlled by carbon canisters (cc) or a regenerative thermal oxidizer (RTO). For sources controlled by RTO, when the RTO is not in operation, emissions are vented to ccs. Equipment marked as RTO* is not currently controlled by the RTO but may be in the future. The RTO is an Anguil, Model No. 150, 4 MMBtu/hr unit designated as TO-110. Serial No. Unavailable. The RTO commenced operation March 2015.		
T4502	146	30 barrel fixed roof tank DGF mix storage tank - RTO*, cc	6/2007	N/A
T4503	146	135 barrel fixed roof tank DGF flocculation storage tank - RTO*, cc	6/2007	N/A
T4504	146	1,240 barrel fixed roof DGF storage tank - RTO*, cc	6/2007	N/A
T4507	146	411 barrel fixed roof DGF effluent tank - RTO*, cc	6/2007	N/A
T4508	146	209 barrel fixed roof DGF float tank - RTO*, cc	6/2007	N/A
T4514	146	4,427 barrel fixed roof oil/water separator tank - RTO*, cc	10/2011	N/A
T4515	146	4,427 barrel fixed roof oil/water separator tank - RTO*, cc	2/2010	N/A
T4516	146	1,574 barrel fixed roof API oil tank - RTO*, cc	2/2010	N/A
T4517	146	1,290 barrel API sludge tank - RTO*, cc	2/2010	N/A
T4518	146	1,290 barrel API sludge tank - RTO*, cc	2/2010	N/A
T60 Lift Station	146	Fixed roof lift station conveying process wastewater - RTO, cc This unit meets the definition of a tank in 40 CFR Part 61 Subpart FF.	2/2010	N/A
API Lift Station	146	Fixed roof lift station conveying process wastewater - RTO, cc This unit meets the definition of a tank in 40 CFR Part 61 Subpart FF.	2/2010	N/A
API Headworks	146	Enclosed individual drain system at the front end of the wastewater treatments system and receives most refinery wastewater. RTO, cc	2/2010	N/A
Centrifuge	146	Centrifuge handling effluent from T-4516 and other sources - RTO, cc The centrifuge will not be operated when the associated control device (RTO) is not in operation.	9/2010 TO installed in 2013 & replaced by RTO in 2016	N/A
		Uncontrolled Sources and Sumps. Emissions from the following sources are estimated using EPA's ToxChem model and/or AP-42 emission factors. The sumps are controlled by carbon canisters (cc)		
T60	149	25,000 barrel external floating roof wastewater equalization storage tank	Modified 2008	N/A
Lab Sump	149	Fixed roof below-grade laboratory sample sump – cc		N/A
Spider Sump	149	Fixed and floating roof below-grade water draw sump for various Plant 1 tanks – cc		N/A
T58 Sump	149	Fixed roof below-grade water draw sump for T58 – cc		N/A
T70 Sump	149	Fixed roof below-grade water draw sump for T70 – cc		N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
T75 Sump	149	Fixed roof below-grade water draw sump for T75 – cc		N/A
T80 Sump	149	Fixed roof below-grade water draw sump for T80 – cc		N/A
T775 Sump	149	Fixed roof below-grade water draw sump for T775 – cc		N/A
T777 Sump	149	Fixed roof below-grade water draw sump for T777 – cc		N/A
T-26	149	Aeration Tank A		N/A
T-4511	149	Aeration Tank B		N/A
T-28	149	Clarifier A		N/A
T4512	149	Clarifier B		N/A
L1	149	Lagoon 1		N/A
L2	149	Lagoon 2		N/A
L3	149	Lagoon 3		N/A
L4	149	Lagoon 4		N/A
T-29	149	Sludge Thickener Tank		N/A
MBR	149	Train A Improvement Project Equipment (Membrane Bioreactor (MBR) Equipment: Aeration Basin 1 and 2, ultra-filtration (UF) and MBR Splitter Boxes, Membrane Tanks 2 through 7 (Tanks 2 – 4 will be in MBR service and Tanks 5 – 7 will be UF service).	Projected for July 2017	
		Fugitive VOC Emission Sources		
F102	020	Equipment Leaks associated with components in the Asphalt Processing Unit	1993	91AD180-2
F103	008	Equipment Leaks associated with the components in the Number.3 Hydrodesulfurizer System (#3 HDS)	8/1993	91AD180-1
F104	071	Fugitives from Cryogenic Vapor Recovery Unit	8/1989	89AD164
F105	024	Equipment leaks associated with the components in the Number 2 Hydrodesulfurizer System (#2 HDS).	1992	91AD180-4
F106	083	Light Straight Run Distillate Tower Fugitives	12/1985	85AD079
F107	075	Plant wide Fugitive Emissions not Subject to Construction Permit Requirements	Prior to 1950	N/A
F108	091	Fugitives from Vapor Recovery Unit Debutanizer	2002	01AD0363
F109	099	Equipment leaks associated with the components in the Number 4 Hydrodesulfurizer (#4 HDS)	5/2006	04AD0110
F110	101	Equipment leaks associated with the components in the Tail Gas Unit Amine System	4/2006	04AD0111
F111	102	Equipment leaks associated with the components in the modified sour water stripper (SWS) system, specifically SWS column (W-7401)	4/2006	04AD0112
F112	103	Equipment leaks associated with the components in the modified tank farm piping	4/2006	04AD0113
F113	143	Equipment leaks associated with the No. 1 Catalytic Reforming Unit modifications		N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
F114	138	Equipment leaks associated with the GBR Unit	5/2012	09AD1352
F115	144	Equipment leaks associated with Bio-Diesel		N/A
F116	157	Equipment leaks associated with the Relief Valve Project	2015	
F200	153	Pipeline Receipt Station Fugitives	April 2016	N/A
F202	161	Equipment leaks associated with the MPV project	September 2017	
F204	164	Hydrogen (H_2) Plant Individual Drain Systems	2006	
F205	167	Equipment leaks associated with Plant 1 Rail Rack RSR Compliance Project (replace flare with VCU)	2018	
F206	168	Equipment leaks associated with the No. 2 HDS Tier 3 Ultra-Low Sulfur Gasoline (ULSG) Project.	November 2019	
F207	169	Equipment leaks associated with fuel gas filter-coalescer for Boiler B-4.	September 2021	20AD0715
F208	170	Equipment leaks associated with the P1 Main Plant Flare Isolation Valve Project	April 2021	
F209	171	Equipment leaks associated with the Reformulated Gasoline (RFG) Project	March 2023	
F210	165	Equipment leaks associated with the Asphalt Unit (Plant 3) Flare RSR Project	2019	
		Miscellaneous Sources		
D001	APEN Exempt[2]	Cold Cleaner Solvent Degreasers		N/A
D004	N/A[2]	Industrial Solvent Cleaning		
D002	APEN Exempt[2]	Emergency Engines. Three (3) diesel fuel-fired fire pump engines, each rated at 481 hp and 25.5 gal/hr, make and model numbers not available.	1993	N/A
D003	APEN Exempt[2]	Emergency Generator (Plant 1 Control Room. John Deere, Model No. 4045HF275, diesel fuel-fired emergency generators, Rated at 157 hp and 8.1 gal/hr (at 100% load), Serial No. PE4045H504772.	2006 Engine Manufactured 9/6/2005	
P1AC1 & P1AC2	APEN Exempt[2]	Emergency Air Compressors. Two (2) Cummins Model No. QSX15 525, Diesel Fuel-Fired Engines, Serial Nos. 80039797 and 80046261. Each Engine Rated at 525 hp (391.4 kW) and 25 gal/hr. Each engine drives an air compressor that supports the plant 1 instrument air supply system. Although the emergency engines are only required to meet Tier 3 standards, the engines meet Tier 4 final standards and iareequipped with selective catalytic reduction (SCR) for NO_X control and a fuel filter for particulate matter control.	2013	N/A
P1EG1	152[5]	PSI, Model No. Industrial 8.8 L, propane-fired internal combustion engine, rated at 162 hp/121 kw (ste) and 1.57 MMBtu/hr (17.1 gal/hr). Serial no. unknown. This engine drives an emergency generator (Kohler Model No. 12REZGC) at the pipeline receipt station.	2013	N/A

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
P1DGTO	160	Tank Cleaning and Degassing Degassing and Cleaning of tanks is controlled by a thermal oxidizer with a maximum rating of 20 MMBtu/hr		
MPVs	N/A[6]	Miscellaneous Process Vents. Miscellaneous process vents are defined in 40 CFR Part 63 Subpart CC §63.641 and include maintenance vents. Process vents can be designated as maintenance vents if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service.		
Y2	158	Plant 3 Cooling Tower: Y2 rated at 2,650 gal/min.	Constructed 1965, possibly replaced/ upgraded 1987	N/A
		Plant 1 Cooling Towers		
Y1	154	Y1 rated at 41,000 gal/min	constructed prior to 1972, modified 1986	N/A
Y3	156	Y3 rated at 15,000 gal/min	2004	
Y4	155	Y4 rated at 7,000 gal/min.	modified 1987 or 1991	
		Sand Creek Remediation Project Equipment		
		Specific equipment information for each air sparge/soil vapor extraction (AS/SVE) system is included in the Table in Condition 5.2 below.		
Pt 606	606	Recovery Trench AS/SVE System Zone F & G	August 2013	12AD1825
Pt 615	615	Suncor Western Property Boundary AS/SVE System	December 2012	12AD1825
Pt 616	616	M & E East AS/SVE System	December 2012	12AD1825
Pt 617	617	RPC AS/SVE System Zone 2	July 2012	12AD1825
Pt 618	618	Metro Utility Corridor AS/SVE System Zones 1 & 2	August 2012	12AD1825
Pt 623	623	Metro South Secondary Area AS/SVE System Zone 1	December 2012	12AD1825
P6 624	624	Metro South Secondary Area AS/SVE System Zone 2	December 2012	12AD1825
Pt 625	625	Recovery Trench AS/SVE System Zone E & H	November 2013	12AD1825
PT 634	634	Metro Utility Corridor AS/SVE System Zones 3 & 4	March 2014	12AD1825
Pt 635	635	PCA Subslab Depressurization	August 2013	
Pt 636	636	NW Boundary Uncontrolled Zones 3 & 4 (AS System only)	Zone 3 6/2014, Zone 4 2015	
Pt 637	637	Laboratory SVE	September 2016	
Pt 638	638	East Burlington Ditch AS/SVE	August 2019	
Pt 639	639	West of Burlington Ditch AS/SVE	TBD 2020	
LO-1	628	Loading of recovered gasoline/reformate into tank trucks	September 2012	12AD1826
D-20	631	Horizontal above ground 21,150 gallon tanks for storage of recovered gasoline/reformate. The tank is vented to two (2) carbon canisters in series.	2013	12AD1826

Emission Unit Number	AIRS Point No.	Description	Startup Date	Construction Permit No.
	627[7]	Two (2) 525 gallon tanks for storage of recovered gasoline/reformate. Tank ID numbers are 17675 and 20529.		N/A

[1]These tanks are APEN exempt because they store butane, propane, or liquefied petroleum gas in tanks less than 60,000 gallons and meet the requirements in Regulation No. 24, Part B, Section II (see Regulation No. 3, Part A, Section II.D.1.zz).
[2]APEN exempt if actual, uncontrolled emissions are below the APEN de minimis level as provided for in Colorado Regulation No. 3, Part A, Section II.D.1.a and/or b.
[3]Emissions from this unit during depressuring and purging are routed to the main plant flare and reported on that APEN. Emissions from this unit during coke-burn-off and catalyst regeneration are below APEN de minimis levels so an APEN is not required.
[4]As long as this engine does not remain in one location for more than 12 consecutive months, it is a non-road engine (not a stationary source) and is not subject to APEN reporting or permitting requirements. Note however, that emissions from the soil vent do require APEN reporting and because VOC emissions from the vent are controlled by the engine, VOC emissions from the engine must be reported.
[5]This engine is APEN exempt but an APEN was submitted, so an AIRS Id No. was assigned.
[6]Group 1 MPVs are routed to a flare. For maintenance vents, prior to venting to atmosphere process liquids are removed or equipment is depressured to a control device, fuel gas system or back to the process until one of the conditions in 63.643(c)(1) (Condition 53.14.1) are met. Emissions from MPVs emitted to atmosphere are below the APEN de minimis level.
[7]AIRS pt was assigned for forty three (43) 525 gallon storage but APEN cancellation request was submitted on 5/28/14 since emissions from each individual tank were below APEN de minimis level.

5.2 Specific information on the air sparge/soil vapor extraction systems (AS/SVE) for the Sand Creek Remediation Project is contained in the below table:

AIRs Point No.	Equipment Description	Current Control Device[1]
606	**Recovery Trench AS/SVE System Zone F & G** SVE Blower: Ametek/Rotron, Model No. EN979BK72WL, rated at 750 scfm, S/N BP643244.	CC-MET-8 (north), -8a (middle) and -8b (south). Three (3) sets of two carbon canisters (cc) in series. Rated at 1,500 scfm (500 scfm per cc set).
615	**Suncor Western Property Boundary AS/SVE** Zones 1 and 2 SVE Blowers: One (1) Roots, Model No. 718-U-RAI, S/N 1211960538 and One (1) Roots Model No. 718-U-RAI-B, S/N 1909B21648 each blower rated at 1,000 scfm. RTO in service December 2012.	TO-SUN-2, Anquill, Model No. 100, Regenerative Thermal Oxidizer (RTO), Rated at 3.0 MMBtu/hr and 10,000 scfm.
616	**M & E East AS/SVE System** SVE Blowers: One (1) Roots, Model No. 615-U-RAI, Rated at 1,200 scfm, S/N 1211960542 and One (1) Eurus, Model No. ZZ6L, Rated at 1,200 scfm, S/N ZZ00329U.	CC-MET-9 (north), -9a (middle) and -9b (south). Three (3) sets of two ccs in series. Rated at 1,500 scfm (500 scfm per cc set).

AIRs Point No.	Equipment Description	Current Control Device[1]
617	**RPC AS/SVE System Zone 2**	CO-RPC-1, Electric Catalytic Oxidizer CatOX-E1000, Rated at 96kW (0.33 MMBtu/hr) and 750 scfm.
	SVE Blowers: Two (2) American Fan, Model No. AVP3-6-21A, Each Rated at 750 scfm, S/Ns DX4124520083 and DX4124520013.	
	Booster Blower: American Fan, Model No. AF15-8-1121, Rated at 1,500 scfm, S/ 123798K-2. Booster blower is between the SVE blowers and the control device.	
618	**Metro Utility Corridor AS/SVE System Zones 1 & 2**	CC-MET-7a (east) and 7b (west) Two (2) sets of two ccs in series. Rated at 1,000 scfm (500 scfm per cc set).
	Zone 1 SVE Blower: American Fan, Model No. 5N-04F-26.54N, Rated at 750 scfm, S/N 002972-1	
	Zone 2 SVE Blower: American Fan, Model No. 5N-04F-26.5N, Rated at 750 scfm, S/N WO-002972-2	
	Booster Blower: American Fan, Model No. AVP-4-10F-19B, Rated at 1,500 scfm, S/N WO-002913. Booster blower is between the SVE blowers and the control device.	
623	**Metro South Secondary Area AS/SVE System Zone 1**	CC-MET-6a (north), -6b (middle) and -6c (south). Three (3) sets of two ccs in series. Rated at 1,500 scfm (500 scfm per cc set).
	SVE Blower: American Fan, Model No. 05N-04F-26.5N, Rated at 750 scfm, S/N WO-003042-1-2A	
	Booster Blower: American Fan, Model No. BC-6-08F-24B, Rated at 2,950 scfm, S/N 125785-001-2 (also WO 003042-1-2). Booster blower is between the SVE blowers and the control device. This blower is also used at AIRs Pt 624.	
624	**Metro South Secondary Area AS/SVE System Zone 2**	CC-MET- 6a (north), -6b (middle) and -6c (south). Three (3) sets of two ccs in series. Rated at 1,500 scfm (500 scfm per cc set).
	SVE Blower: American Fan, Model No. 05N-04F-26.5N, Rated at 750 scfm, S/N WO- 003042-1-2B. The Booster Blower listed for AIRs point 624 is used for this point.	
625	**Recovery Trench AS/SVE System Zone E & H**	CC-MET- 8 (north), -8a (middle) and -8b (south). Three (3) sets of two ccs in series. Rated at 1,500 scfm (500 scfm per cc set).
	SVE Blower: Roots, Model No. 615-U-RAI DSL Rated at 750 scfm, S/N 504996617.	
634	**Metro Utility Corridor AS/SVE System Zones 3 & 4**	CC-MET- 7c, -7d, -7e and -7f Four (4) sets of two ccs in series. Rated at 2,000 scfm (500 scfm per cc set). The carbon canisters replaced a catalytic oxidizer (CO-MET-1) in April 2015,
	Zone 3 SVE Blowers: Two (2) Ametek/Rotron, Model No. EN14BK72MWL, Rated at 800 and 850 scfm, S/Ns BP633330 and BP594013-1.	
	Zone 4 SVE Blowers: Two (2) Ametek/Rotron, Model Nos. EN14DX72MWL and EN14BK72MWL, each rated at 850 scfm, S/Ns BP806827 and BP612538-2.	
	Booster Blower: American Fan, Model No. AVP-4-10F-19B, Rated at 2,060 scfm, S/N WO-002913	
635	**PCA Subslab Depressurization**	CC-SUN-3 One (1) set of two ccs in series. Rated at 500 scfm.
	SVE Blower: Ametek/Rotron, Model No. EN858BD72W, Rated at 500 scfm, S/N BP409943.	

AIRs Point No.	Equipment Description	Current Control Device[1]
636	**NW Boundary Uncontrolled Zones 3 & 4(AS System only**)	Uncontrolled
	AS Blowers: Two (2) GE Oil & Gas Roots Rotary Lobe Blowers, Model No. 1009-RAS-J-H-N-PL-71.0-L-B-OGE, each rated at 1,060 scfm, S/Ns LR13-8578 and LR13-8579. These AS blowers also inject air into wells for Pt 615.	
	Zone 3 has 28 wells with a presumed injection rate of 10 scfm per well.	
	Zone 4 has 21 wells with a presumed injection rate of 10 scfm per well.	
637	**Laboratory SVE**	CC-SUN-2 One (1) set of ccs in series. Rated at 500 scfm.
	SVE Blower: Ametek/Rotron, Model No. EN404AR58ML, Rated at 107 scfm, S/N 11492-2.	
638	**East Burlington Ditch AS/SVE**	CC-MET-5c and -5a (SVE 1209958308) CC-MET- 5b and -5d (SVE 1209957737) Four (4) sets of two ccs in series. Rated at 2,000 scfm (500 scfm per cc set).
	SVE Blowers: Two (2) Roots, Model No. 615-U-RAI, Each Rated at 650 scfm, S/Ns 1209958308 and 1209957737.	
639	**West of Burlington Ditch AS/SVE**	
	SVE Blowers: Two (2) Roots, Model No. URAI-59, Each rated at 500 scfm, S/Ns TBD	CC-MET-10a (north) and -10b (south) Two (2) sets of two ccs in series. Rated at 1,000 scfm (500 scfm per cc set).

[1]As specified in Condition 67.6, the control devices may be replaced or removed as long as the emissions limitations can be met.

6. Compliance Assurance Monitoring (CAM)

6.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Unit P103 – FCCU Regenerator

AIRs Pt 615 - Suncor Western Property Boundary AS/SVE System

AIRS Pt 617 – RPC Zone 2 AS/SVE System

P1DGTO – Tank Cleaning and Degassing Thermal Oxidizer (TO)

F201 - Plant 1 Wastewater Treatment System RTO and API Headworks (when controlled by carbon canisters)

R101 – Rail Loading Rack

R102 – Truck Loading Rack

F2 – Plant 3 (AU) Flare

F3 – GBR Flare

See Section II, Condition 60 for compliance assurance monitoring requirements.

SECTION II - Specific Permit Terms

1. Tanks for Which Construction Permits Are Not Required – T67, T70, T74, T75, T77, T78, T80, T776, T57, T59, T64, T65, T66, T68, T69, T71, T72, T76, T105, T112, T140, T142, T144, T145, T146, T147, T182, T191, T192, T193, T194, Pipeline Receipt Station Sump

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	1.1		TankESP Program	Recordkeeping and Calculation	Annually
MACT	1.2	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
RACT	1.3	See Condition 1.3		See Condition 1.3	
Throughput	1.4			Recordkeeping	Annually
BWON **– Pipeline Receipt Station Sump**	1.5	See 40 CFR Part 61 Subpart FF (Condition 65)		See 40 CFR Part 61 Subpart FF (Condition 65)	

1.1 For APEN reporting and fee purposes, annual emissions for each tank shall be calculated using a version of the TankESP program based on the June 2020 version of AP-42, Chapter 7.1 and actual throughput (as required by Condition 1.4) for the tank. Emissions shall be based on the average (or numerically greater) Reid Vapor Pressure (RVP) of the materials stored over the annual period. Note that if a new version of AP-42, Chapter 7.1 is published, Suncor may be required to modify this condition to include the new calculation methodologies to calculate emissions.

1.2 These sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 53 of this permit. The following tanks are only subject to Conditions 53.37 and 53.86 (Group 2 Tanks): T57, T59, T64, T65, T66, T68, T69, T71, T72, T74, T76, T105, T112, T140, T142, T144, T145, T146, T147, T182, T191, T192, T193 and T194

1.3 These sources are subject to Colorado Regulation No. 24 requirements as follows:

1.3.1 These tanks are subject to the requirements in Part B, Sections I.A and IV.A.1 as set forth in Conditions 39.1 and 41.1 of this permit.

1.3.2 Except for T182 and the pipeline receipt station, these tanks are subject to the requirements in Part B, Section IV.B.2.b as set forth in Condition 41.2.2 of this permit.

1.3.3 Tanks T64, T65, T66 and T72 are subject to the recordkeeping requirements of Part B, IV.B.2.c(ii)(C) as set forth in Condition 41.2.3 of this permit.

1.3.4 The following tanks are subject to the requirements in Part B, Section IV.B.2.c as set forth in Condition 41.2.3: T67, T70, T75, T77, T78, T80 and T776.

1.3.5 Tank T776 is subject to Part B, Section V as set forth in Condition 42 of this permit.

1.4 The throughputs for each tank shall be monitored and recorded annually. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

1.5 The pipeline receipt station sump is subject to the requirements of 40 CFR Part 61 Subpart FF, as set forth in Condition 65 of this permit.

2. Tank with Unique Requirements, Subject to 40 CFR Part 63, Subpart CC (Group 1) – T1

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	2.1	13.6 tons/year	TANKS	Recordkeeping and Calculation	Monthly
MACT	2.2	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
RACT	2.3	See Condition 2.3		See Condition 2.3	
Throughput	2.4	2,500,000 barrels of gasoline per year		Recordkeeping	Monthly

2.1 Emissions of air pollutants from this tank shall not exceed the limits listed in the above table. (Colorado Construction Permit 01AD0899). Compliance with the annual limits shall be monitored by calculating monthly emissions from the tank using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 2.4). Emissions shall be based on the average (or numerically greater) RVP of the materials stored over the monthly period. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

2.2 This tank is subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 53 of this permit.

2.3 This tank is subject to Colorado Regulation No. 24, Part B, Sections I.A, and IV.B.2.b and c as set forth in Conditions 39.1, 41.2.2, and 41.2.3 of this permit.

2.4 Throughput of gasoline and/or products with a RVP or 13 psia or lower shall not exceed 2,500,000 barrels/year. (Colorado Construction Permit 01AD0899) Compliance with the annual throughput limits shall be monitored by recording throughput monthly. Monthly quantities of throughput shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

3. Tanks with Unique Requirements, Subject to 40 CFR Part 60, Subpart Kb and 40 CFR 63, Subpart CC (Group 1) – T34, T55, T58, T96, T97, T116, T775, T2010

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	3.1	T34: 9.6 tons/year T55: 4.26 tons/year T58: 4.17 tons/year T96/97*: 6.72 tons/year T116: 7.1 tons/year T775: 7.1 tons/year T2010: 4.98 tons/year	TANKS	Recordkeeping and Calculation	Monthly
RACT	3.2 – 3.7	See Conditions 3.2 – 3.7		See Conditions 3.2 – 3.7	
NSPS	3.8	General Provisions – Subpart A (Condition 56) Specific Requirements – Subpart Kb (Condition 48)		See 40 CFR Part 60 Subparts A (Condition 56) and Kb (Condition 48)	
MACT	3.9	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Throughput	3.10	T34: 5,840,000 barrels of gasoline per year T55: 8,000,000 barrels of petroleum feedstock per year T58: 6,260,000 barrels of petroleum liquids per year T96: 3,000,000 barrels of gasoline per year T97: 2,000,000 barrels of gasoline per year T116: 3,000,000 barrels of gasoline blending components per year T775: 13,140,000 barrels of crude oil per year T2010: 8,000,000 barrels of gasoline per year		Recordkeeping	Monthly

*Emissions limit for tanks T96 and T97 is a combined limit. Limit applies to emissions from both tanks together.

3.1 Emissions of air pollutants from these tanks shall not exceed the limits listed in the above table. (Colorado Construction Permits 87AD110 (T96 & T97), as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APEN submitted on 12/28/12, 87AD210 (T116), 97AD0699 (T2010), as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APEN submitted on 6/1/09, 98AD0896 (T775), as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase emissions per APEN submitted 9/15/06, 99AD0931 (T55), as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APEN submitted on 7/23/13, 01AD0609 (T34), as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APEN submitted on 2/17/16 and for T-58, as provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APEN submitted on 4/7/08). Compliance with the annual limits shall be monitored by calculating monthly emissions from each tank using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 3.10). Emissions shall be based on the average (or numerically greater) RVP of the materials stored over the monthly period. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

3.2 These tanks are subject to Colorado Regulation No. 24, Part B, Section I.A, as set forth in Condition 39.1 of this permit.

3.3 These tanks are subject to Colorado Regulation No. 24, Part B, Section IVA.1, as set forth in Condition 41.1 of this permit.

3.4 T96, T97, and T116 are subject to Colorado Regulation No. 24, Part B, IV.B.2.a as set forth in Condition 41.2.1 of this permit.

3.5 These tanks are subject to Colorado Regulation No. 24, Part B, Section IV.B.2.b, as set forth in Condition 41.2.2 of this permit.

3.6 T34, T55, T58, T775 and T2010 are subject to Colorado Regulation No. 24, Part B, Section IV.B.2.c as set forth in Condition 41.2.3 of this permit.

3.7 T58 and T775 are subject to Colorado Regulation No. 24, Part B, Section V, as set forth in Condition 42 of this permit.

3.8 Except for tank T58, these tanks are subject to NSPS requirements as follows:

3.8.1 These tanks are subject to the NSPS general provisions in 40 CFR Part 60, Subpart A as set forth in Condition 56 of this permit.

3.8.2 These tanks are subject to the specific NSPS requirements for volatile organic liquid (including petroleum liquids) storage vessels in 40 CFR Part 60, Subpart Kb, as set forth in Condition 48 of this permit.

3.9 These sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Conditions 53 of this permit.

3.10 These tanks shall be limited to throughputs as follows.

T34: Throughput of gasoline and/or products with a RVP of 15 psia or lower (shall not exceed 5,840,000 barrels per year. (Colorado Construction Permit 01AD0609, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase the vapor pressure of products stored as specified in the modification application submitted on 2/17/16)

T55: Throughput of petroleum feedstocks and/or products with a RVP of 15 psia or lower shall not exceed 8,000,000 barrels per year. (Colorado Construction Permit 99AD0931, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set throughput limits as specified in the APEN submitted on 7/23/13)

T58: Throughput of petroleum liquids with a RVP of 7 psia or lower shall not exceed 6,260,000 barrels per year. (As provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include throughput specified in the APEN submitted on 4/7/08)

T96: Throughput of gasoline and/or products with a RVP of 15 psia or lower shall not exceed 3,000,000 barrels per year. (Colorado Construction Permit 87AD110, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase the RVP of material stored as requested in 12/28/12 application)

T97: Throughput of gasoline and/or products with a RVP of 15 psia or lower shall not exceed 2,000,000 barrels per year. (Colorado Construction Permit 87AD110, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase the RVP of material stored as requested in 12/28/12 application)

T116: Throughput of gasoline blending components with a RVP of 13 or lower shall not exceed 3,000,000 barrels per year. (Colorado Construction Permit 87AD210)

T775: Throughput of crude oil and/or products with a RVP of 10 psia or lower shall not exceed 13,140,000 barrels per year. (Colorado Construction Permit 98AD0896)

T2010: Throughput of gasoline and/or products with a RVP of 15 psia or lower shall not exceed 8,000,000 barrels per year. (Colorado Construction Permit 97AD0699, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include throughput specified in the APEN submitted on 6/1/09)

Compliance with the annual throughput limits shall be monitored by recording the throughput for each tank monthly. Monthly quantities of throughput from each tank will be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month rolling total shall be calculated using the previous twelve months data. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

4. Tanks with Unique Requirements, Subject to 40 CFR 63, Subpart CC (Group 1 and 2) – T2, T3, T52, T62, T94, T774, T777, T778, T3801

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	4.1	T2: 3.7 tons/year T3: 3.7 tons/year T52: 0.11 tons/year T62: 0.13 ton/year T94: 1.48 tons/year T774: 0.54 tons/yr T777: 2.75 tons/yr T778: 3.54 tons/yr T3801: 2.19 tons/yr	TANKS	Recordkeeping and Calculation	Monthly
RACT	4.2-4.5	See Conditions 4.2-4.5		See Conditions 4.2-4.5	
MACT	4.6	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Tank 62 Requirement	4.7	EFR w/ double seals			
Throughput	4.8	T2: 12,000,000 barrels of petroleum products per year T3: 12,000,000 barrels of petroleum products per year T52: 1,300,000 barrels of sour water with a floating diesel layer per year T62: 2,000,000 barrels of jet 50/kerosene per year T94: 3,331,928 barrels of jet kerosene per year T774: 13,898,052 barrels of diesel per year T777: 9,155,066 barrels of LSR/Naphtha/Kerosene per year T778: 13,500,000 barrels of crude oil per year T3801: 20,095,096 barrels of jet kerosene per year		Recordkeeping	Monthly
Tanks T52, T774 & T777: Restrictions on Relaxing Emission Limitations	4.9	See Condition 4.9		Certification	Annually

4.1 Emissions of air pollutants from these tanks shall not exceed the limits listed in the above table (Colorado Construction Permits 03AD0031 (T2), 85AD027-2 (T94), 90AD474 (T62), as modified in accordance with the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part

B, Section II.A.6 and Part C, Section X to revise emission limits as requested on the APEN submitted on May 30, 2017, red-lined September 9, 2019, 99AD0432 (T3), 04AD0114 (T774), 04AD0115 (T777) and for T3801, T52 and T778 as modified in accordance with the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APEN submitted on 11/1/10 (T3801), 3/3/10 (T52) and 12/9/09 (T778)). Compliance with the annual limits shall be monitored by calculating monthly emissions from each tank using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 4.8). Emissions shall be based on the average (or numerically greater) RVP of the material stored over the monthly period. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

4.2 These tanks are subject to Colorado Regulation No. 24, Part B, Section I.A, as set forth in Condition 39.1 of this permit.

4.3 These tanks are subject to Colorado Regulation No. 24, Part B, Section IV.B.2.b, as set forth in Condition 41.2.2 of this permit.

4.4 T52, T62 and T774 are subject to the recordkeeping requirements of Colorado Regulation No. 24, Part B, Section IV.B.2.c(ii)(C) as set forth in Condition 41.2.3 of this permit.

4.5 T777 and T778 are subject to Colorado Regulation No. 24, Part B, Section IV.B.2.c as set forth in Condition 41.2.3 of this permit.

4.6 The following sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 53 of this permit: T2, T3, T52, T62, T94, T774, T777, T778 and T3801. Note that T2, T3, T52, T62, T94, T774 and T3801 are Group 2 tanks and T777 and T778 are Group 1 tanks.

4.7 T62: The tank shall be equipped with an external floating roof with double seals. (Colorado Construction Permit 90AD474)

4.8 These tanks shall be limited to throughputs as follows:

T2: Throughput of petroleum distillate products with a RVP of 0.029 psia or lower shall not exceed 12,000,000 barrels per year. (Colorado Construction Permit 03AD0031)

T3: Throughput of petroleum distillate products with a RVP of 0.029 psia or lower shall not exceed 12,000,000 barrels per year. (Colorado Construction Permit 99AD0432)

T52: Throughput of sour water with a floating diesel layer shall not exceed 1,300,000 barrels per year. (As provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include throughput specified in the APEN submitted on March 3, 2010).

T62: Throughput of Jet50/kerosene and/or products with a RVP of 0.029 psia or lower shall not exceed 2,000,000 barrels per year. (Colorado Construction Permit 90AD474, as modified in accordance with the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to revise throughput limits as requested on the APEN submitted on May 30, 2017, red-lined September 9, 2019)

T94: Throughput of jet kerosene and/or materials with a RVP of 0.029 psia or lower shall not exceed 3,331,928 barrels per year. (Colorado Construction Permit 85AD027-2)

T774: Throughput of diesel and/or products with a RVP or 0.022 psia or lower shall not exceed 13,898,052 barrels per year (Colorado Construction Permit 04AD0114).

T777: Throughput of LSR/Naphtha/Kerosene and/or other products with a RVP of 2.7 psia or lower shall not exceed 9,155,066 barrels per year (Colorado Construction Permit 04AD0115).

T778: Throughput of crude oil and/or materials with a RVP of 10 psia or lower shall not exceed 13,500,000 barrels per year (as provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include throughput specified in the APEN submitted on 12/9/08).

T3801: Throughput of jet kerosene and/or petroleum products with a RPV of 0.029 psia or lower shall not exceed 20,095,096 barrels per year. (As provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include throughput specified in the APEN submitted on 11/1/10)

Compliance with the annual throughput limits shall be monitored by recording the throughput for each tank monthly. Monthly quantities of throughput from each tank will be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

4.9 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section VI.B.4).

Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.4 (Tanks T52, T774 and T777), as well Sections II.10 (Y-3 Cooling Tower), II.13 (Boilers B-6 and B-8), II.20 (TGU Incinerator H-25), II.21 (Process Heaters H-1716 and H-1717), II.27 (Process Heater H-2101) and II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H_2 Plant Drain Systems). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants.

5. Tanks with Unique Requirements, Subject to 40 CFR Part 60, Subpart UU, and 40 CFR 63, Subpart CC (Group 2) – T2006, T3201

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	5.1	T2006: 0.2 ton/year T3201: 2.8 tons/year	TANKS	Recordkeeping and Calculation	Monthly
RACT	5.2-5.3	See Conditions 5.2-5.3		See Conditions 5.2-5.3	
NSPS	5.4	General Provisions – Subpart A (Condition 56) Specific Requirements – Subpart UU (Condition 49)		See 40 CFR Part 60 Subparts A (Condition 56) and UU (Condition 49)	
MACT	5.5	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Throughput	5.6	T2006: 4,896,498 barrels of asphalt per year T3201: 5,000,000 barrels of petroleum distillate and/or asphalt per year		Recordkeeping	Monthly

5.1 Emissions of air pollutants from these tanks shall not exceed the limits listed in the above table. (Colorado Construction Permits 96AD881 (T2006), and 03AD0030 (T3201)) Compliance with the annual limits shall be monitored by calculating monthly emissions from each tank using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 5.6). For T3201, if materials other than asphalt are stored, emissions shall be based on the average (or numerically greater) RVP of the material stored over the monthly period. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

5.2 These tanks are subject to Colorado Regulation No. 24, Part B, Section I.A, as set forth in Condition 39.1 of this permit.

5.3 These tanks are subject to Colorado Regulation No. 24, Part B, Section IV.B.2.b, as set forth in Condition 41.2.2 of this permit.

5.4 These tanks are subject to NSPS requirements as follows:

5.4.1 These tanks are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

5.4.2 These tanks are subject to the specific NSPS requirements for asphalt processing and asphalt roofing manufacture in 40 CFR Part 60, Subpart UU, as set forth in Condition 49 of this permit.

5.5 The following sources are subject to 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 53 of this permit: T2006, T3201.

5.6 These tanks shall be limited to throughputs as follows.

T2006: Throughput of asphalt shall not exceed 4,896,498 barrels per year. (Colorado Construction Permit 96AD881, revised in accordance with Section I, Condition 1.3 of this permit)

T3201: Throughput of petroleum distillate and/or asphalt products with a RVP of 0.022 psia or lower shall not exceed 5,000,000 barrels per year. (Colorado Construction Permit 03AD0030)

Compliance with the annual throughput limits shall be monitored by recording the throughput for each tank monthly. Monthly quantities of throughput from each tank will be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

6. Tanks with Unique Requirements, Subject to 40 CFR Part 60, Subpart Kb and Storing Organic Liquids – T7208

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	6.1	0.39 ton/year	TANKS	Recordkeeping and Calculation	Monthly
RACT	6.2	See Condition 6.2		See Condition 6.2	
NSPS	6.3	General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60 Subparts A (Condition 56) and Kb (Condition 48)	
		Specific Requirements – Subpart Kb (Condition 48)			
Throughput	6.4	2,095,000 barrels of organic liquids per year		Recordkeeping	Monthly

6.1 Emissions of air pollutants from this tank shall not exceed the limits listed in the above table. (Colorado Construction Permit 88AD240, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase the emission limitations per August 17, 2010 modification request) Compliance with the annual limits shall be monitored by calculating monthly emissions from each tank using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 6.4). Emissions shall be based on the average (or numerically greater) RVP of the material stored over the monthly period. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

6.2 This tank is subject to Colorado Regulation No. 24, Part B, Sections I.A and B, as set forth in Conditions 39.1 and 39.2 of this permit.

6.3 This tank is subject to NSPS requirements as follows:

6.3.1 This tank is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

6.3.2 This tank is subject to the specific NSPS requirements for volatile organic liquid (including petroleum liquids) storage vessels in 40 CFR Part 60, Subpart Kb, as set forth in Condition 48 of this permit.

6.4 Throughput of organic liquids with true vapor pressure (TVP) less than or equal to 0.619 psia at 60°F shall not exceed 2,095,000 barrels per year. (Colorado Construction Permit 88AD240, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase the throughput per August 17, 2010 modification request) Compliance with the annual throughput limits shall be monitored by recording the throughput monthly. Monthly quantities of throughput shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

7. Tanks with Unique Requirements, Subject to Colorado Regulation No. 24, Part B, Section II – D-811, T81, T82, D-812, D-813, D-814, T90, T91, T92 and T400

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
RACT	7.1	Minimize vapor loss		Leak Detection and Repair	See Condition 40

7.1 These sources are subject to Colorado Regulation No. 24, Part B, Section II as set forth in Condition 40 of this permit.

8. Stationary Internal Combustion Engines

D002 - Three (3) Diesel Fuel Fired Emergency Fire Pump Engines (each rated at 481 hp)
D003 -One (1) Diesel-Fuel Fired Emergency Generator Engine (rated at 157 hp) – P1 Control Room

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
MACT ZZZZ Requirements	8.1	Change Oil and Filter Inspect Air Cleaner Inspect all Hoses and Belts		See Condition 8.1.	
SO_2	8.3	0.3 lb SO_2/bbl/day of oil processed		See Condition 8.3	Daily, Monthly
Fuel Consumption	8.4			Calculation	Daily
SO_2	8.5.	0.8 lb/MMBtu		Fuel Restriction	Only Diesel Fuel is Used as Fuel
Opacity	8.6	Not to Exceed 20% Except as Provided for Below		EPA Method 9	See Condition 8.6
		For Startup – Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes			

Note that these engines are exempt from the APEN reporting requirements in Regulation No. 3, Part A and the minor source construction permit requirements provided actual, uncontrolled emissions do not exceed the APEN de minimis level (1 ton/yr of NO_X) per Colorado Regulation No. 3, Part A, Section II.D.1.a and Part B, Section II.D.1.a. Based on AP-42 emission factors (Section 3.3, dated 10/96, Table 3.3-1, NO_X – 0.031 lb/hp-hr) and design rate (fire pump engines: 481 hp, emergency generator: 157 hp), emissions exceed the APEN de minimis level at 135 hrs/yr for each emergency fire pump engine and 411 hrs/yr for the emergency generator.

P1AC1 & P1AC2 - Two (2) Diesel Fuel-Fired Emergency Air Compressor Engines (each rated at 525 hp/391.4 kW)

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
SO_2	8.3	0.3 lb SO_2/bbl/day of oil processed		See Condition 8.3	Daily, Monthly
Fuel Consumption	8.4			Calculation	Daily
Opacity	8.6	Not to Exceed 20% Except as Provided for Below		EPA Method 9	See Condition 8.6
		For Startup – Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes			
NSPS Subpart IIII	8.7	NO_X-NMHC – 4.0 g/kw-hr CO – 3.5 g/kw-hr PM – 0.20 g/kw-hr		See Condition 8.7	

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
MACT ZZZZ Requirements	8.8	Initial Notification		Notification	Within 120 Days of Startup

Note that these engines are exempt from the APEN reporting requirements in Regulation No. 3, Part A and the minor source construction permit requirements provided actual, uncontrolled emissions do not exceed the APEN de minimis level (1 ton/yr of NO_X) per Colorado Regulation No. 3, Part A, Section II.D.1.a and Part B, Section II.D.1.a. Based on the NSPS NO_X limit (4.0 g/kW-hr) and design rate (391.4 kW), emissions exceed the APEN de minimis level at 580 hrs/yr for each engine.

P1EG1 - Propane-Fired Emergency Generator (rated at 162 hp/121 kW) – Pipeline Receipt Station

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
MACT ZZZZ Requirements	8.2	Compliance with MACT met by complying with NSPS Subpart JJJJ		See Condition 8.2.	
SO_2	8.3	0.3 lb SO_2/bbl/day of oil processed		See Condition 8.3	Daily, Monthly
Fuel Consumption	8.4			Calculation	Daily
Opacity	8.6	Not to Exceed 20% Except as Provided for Below		EPA Method 9	See Condition 8.6
		For Startup – Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes			
NSPS Subpart JJJJ	8.9	HC-NO_X – 2.7 g/kw-hr CO – 4.4 g/kw-hr		See Condition 8.9	
Propane Requirements	8.10	Propane must be purchased and isolated from refinery fuel gas system.		See Condition 8.10	

Note that this engine is exempt from the APEN reporting requirements in Regulation No. 3, Part A and the minor source construction permit requirements provided actual, uncontrolled emissions do not exceed the APEN de minimis level (1 ton/yr of NO_X) per Colorado Regulation No. 3, Part A, Section II.D.1.a and Part B, Section II.D.1.a. Based on the NSPS NO_X limit (2.7 g/kW-hr) and design rate (121 kW), emissions exceed the APEN de minimis level at 2,777 hrs/yr.

8.1 The **emergency fire pump and P1 control room emergency generator engines** are subject to the requirements in 40 CFR Part 63 Subpart ZZZZ, “National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines”, as follows:

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63 Subpart ZZZZ published in the Federal Register on December 4, 2020. However, if revisions to this Subpart are promulgated at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63 Subpart ZZZZ.

The D. C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements allowing emergency engines to operate for limited hours for demand response. Upon issuance of the mandate § 63.6640(f)(2)(ii)-(iii) (Conditions 8.1.11.2.b and 8.1.11.2.c) have no legal effect. Operation of emergency engines is limited to emergency situations specified in 63.6640(f)(1) (Condition 8.1.11.1); maintenance checks and readiness testing for a limited number of hours per year as specified in 63.6640(f)(2)(i) (Condition 8.1.11.2.a); and certain non-emergency situations for a limited number of hours per year as specified in 63.6640(f)(3)–(4) (Condition 8.1.11.3). See EPA memorandum dated April 15, 2016 regarding "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" for more information.

It should be noted that additional revisions to the requirements in 40 CFR Part 63 Subpart ZZZZ are expected to be made in response to issues related to legal action associated with the allowable hours of operation provisions for emergency engines regarding engines used for demand response. Therefore, the requirements below may change in the future.

Note that as of the date of revised permit issuance **July 9, 2024**, the requirements in 40 CFR Part 63 Subpart ZZZZ promulgated after July 1, 2007 have not been adopted into Colorado Regulation No. 8, Part E by the Division and are therefore not state-enforceable. In the event that the requirements in 40 CFR Part 63 Subpart ZZZZ promulgated after July 1, 2007 are adopted into Colorado Regulations, they will become state-enforceable.

When do I have to comply with this subpart (§60.6595)

8.1.1 If you have an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than May 3, 2013. (§63.6595(a)(1))

What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions (§63.6602)

8.1.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c of 40 CFR Part 63 Subpart ZZZZ which apply to you. Compliance with the numerical emission limitations established of 40 CFR Part 63 Subpart ZZZZ is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 of 40 CFR Part 63 Subpart ZZZZ. (§63.6602)

Note that these engines are not subject to emission limitations but are subject to work practice standards.

The requirements in Table 2c of 40 CFR Part 63 Subpart ZZZZ that apply to these engines are as follows:

8.1.2.1 Change oil and filter every 500 hours of operation or annually whichever comes first. (40 CFR Part 63 Subpart ZZZZ, Table 2c, item 1.a)

8.1.2.2 Inspect air cleaner every 1,000 hours of operation or annually whichever comes first. (40 CFR Part 63 Subpart ZZZZ ,Table 2c, item 1.b)

8.1.2.3 Inspect all hoses and belts every 500 hours of operation or annually whichever comes first, and replace as necessary. (40 CFR Part 63 Subpart ZZZZ Table 2c, item 1.c)

8.1.2.4 During periods of startup you must minimize the engine’s time spent at idle and minimize the engine’s startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. (40 CFR Part 63 Subpart ZZZZ Table 2c, item 1)

Notwithstanding the above requirements, the following applies:

8.1.2.5 If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Conditions 8.1.2.1through 8.1.2.3, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. (40 CFR Part 63 Subpart ZZZZ, Table 2c, footnote 1)

8.1.2.6 Sources have the option to utilize an oil analysis program as described in Condition 8.1.9 in order to extend the specified oil change requirement in Condition 8.1.2.1. (40 CFR Part 63 Subpart ZZZZ, Table 2c, footnote 2)

8.1.2.7 Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices. (40 CFR Part 63 Subpart ZZZZ, Table 2c, footnote 3)

What fuel requirements must I meet if I own or operate a stationary CI RICE? (§ 63.6604)

8.1.3 Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in Conditions 8.1.11.2.b and 8.1.11.2.c or that operates for the purpose specified in §

63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. (§ 63.6604(b))

What are my general requirements for complying with this subpart? (§63.6605)

8.1.4 You must be in compliance with the emission limitations, operating limitations and other requirements in this subpart that apply to you at all times. (§63.6605(a))

8.1.5 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 Division 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. (§63.6605(b))

What are my monitoring, installation, collection, operation, and maintenance requirements? (§63.6625)

8.1.6 If you own or operate an existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major 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. (§63.6625(e)(2))

8.1.7 If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed. (§63.6625(f))

8.1.8 If you operate a new 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 Tables 1a, 2a, 2c, and 2d of 40 CFR Part 63 Subpart ZZZZ apply. (§63.6625(h))

8.1.9 If you own or operate a stationary CI engine that is subject to the work, operation or management practices in Condition 8.1.2, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Condition

8.1.2.1. The oil analysis must be performed at the same frequency specified for changing the oil in Condition 8.1.2.1. 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. (§63.6625(i))

How do I demonstrate continuous compliance with the emission limitations, operating limitations and other requirements? (§63.6640)

8.1.10 You must demonstrate continuous compliance with each emission limitation, operating limitation and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d [Conditions 8.1.2.1 through 8.1.2.4] to this subpart that apply to you according to methods specified in Table 6 to this subpart. (§63.6640(a))

8.1.10.1 Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (Subpart ZZZZ, Table 6, item 9.a.i); or

8.1.10.2 Develop and follow 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. (Subpart ZZZZ, Table 6, item 9.a.ii)

8.1.11 If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in Conditions 8.1.11.1 through 8.1.11.3 of this permit. In order for the engine to be considered an emergency stationary RICE under 40 CFR Part 63 Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 8.1.11.1 through 8.1.11.3 of this permit, is prohibited. If you do not operate the engine according to the requirements in Conditions 8.1.11.1 through 8.1.11.3 of this permit, the engine will not be considered an emergency engine under 40 CFR Part 63 Subpart ZZZZ and must meet all requirements for non-emergency engines. (§63.6640(f))

8.1.11.1 There is no time limit on the use of emergency stationary RICE in emergency situations. (§63.6640(f)(1))

8.1.11.2 You may operate your emergency stationary RICE for any combination of the purposes specified in Conditions 8.1.11.2.a through 8.1.11.2.c for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed Condition 8.1.11.3 counts as part of the 100 hours per calendar year allowed by this condition. (§63.6640(f)(2))

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. (§63.6640(f)(2)(i))

b. Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. (§63.6640(f)(2)(ii))

c. Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. (§63.6640(f)(2)(iii))

8.1.11.3 Emergency stationary RICE located at major sources of HAP 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 and emergency demand response provided in Condition 8.1.11.2 of this permit. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (§63.6640(f)(3))

What reports must I submit and when? (§63.6650)

8.1.12 If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in Conditions 8.1.11.2.b or

8.1.11.2.c, you must submit an annual report according to the requirements in 63.665(h)(1) - (3). (63.6650(h))

What records must I keep? (§63.6655)

8.1.13 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 your own maintenance plan if you own or operate an existing stationary emergency RICE. (§63.6655(e) and §63.6655(e)(2))

8.1.14 If you own or operate an existing emergency stationary CI RICE with a site rating of less than or equal to 500 brake Hp located at major source of HAP emissions that 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. If the engine is used for the purposes specified Conditions 8.1.11.2.b or 8.1.11.2.c, the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes. (§63.6655(f) and §63.6655(f)(1))

In what form and how long must I keep my records? (§ 63.6660)

8.1.15 Records shall be kept in the form and for the duration specified in § 63.6660.

What parts of the General Provisions apply to me? (§ 63.6665)

8.1.16 Table 8 of Subpart ZZZZ shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. (§ 63.6665) The general provisions that apply to these engines include, but are not limited to the following:

8.1.16.1 Prohibited activities in § 63.4(a).

8.1.16.2 Circumvention in § 63.4(b).

8.2 The **pipeline receipt station emergency generator** is subject to the requirements in 40 CFR Part 63 Subpart ZZZZ, “National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines”, as follows:

Note that as of the date of revised permit issuance **July 9, 2024**, the requirements in 40 CFR Part 63 Subpart ZZZZ promulgated after July 1, 2007 have not been adopted into Colorado Regulation No. 8, Part E by the Division and are therefore not state-enforceable. In the event that the Division adopts these requirements, these requirements will become both state and federally enforceable.

A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part. (§ 63.6590(c)(4))

8.3 Sulfur dioxide emissions **from each engine** shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit.

Daily SO_2 emissions **from each engine** shall be calculated, using the daily fuel consumption (as required by Condition 8.4) in the following equations:

For diesel fuel-fired engines:

SO_2 (lb/day) = 15 lbs S/10^6 lbs diesel x gal diesel/day x 7.05 lb diesel/gal of diesel x lb-mole S/32 lb S x lb-mole SO_2/lb-mole S x 64 lb SO_2/lb-mole SO_2

For propane fuel-fired engines:

SO_2 (lb/day) = 0.35 lb SO_2/1000 gal propane x gal propane/day

Where: 0.35 lb SO_2/1000 gal from San Diego County Air Pollution Control District calculation procedures, uncontrolled propane-fire engine

8.4 Fuel consumption **from each engine** shall be monitored and recorded daily, when the engine is operated. Recording fuel consumption/hours of operation is not required on days the engine is not operated. Daily fuel consumption shall be determined based on hours of operation for the engine and the maximum hourly fuel consumption rate for that engine (D002 (emergency fire pump engine) – 25.5 gal/hr, each, D003 (P1 control room emergency generator) – 8.1 gal/hr, P1AC1 & P1AC2 – 25 gal/hr, each and P1EG1 (pipeline receipt station emergency generator) – 27 gal/hr) (daily monitoring is required to demonstrate compliance with Colorado Regulation No. 1, Section VI requirements, as described in Conditions 8.3 and 38.1).

8.5 Sulfur Dioxide (SO_2) emissions **from each emergency fire pump and the P1 control room emergency generator engine** shall not exceed 0.8 lbs/MMBtu (Colorado Regulation No. 1, Section VI.B.4.b. (i)). In the absence of credible evidence to the contrary, compliance with the SO_2 emission limitation shall be presumed since only diesel fuel is permitted to be used as fuel in these engines.

8.6 Opacity of emissions from these engines shall not exceed the following:

8.6.1 Except as provided for in Condition 8.6.2 below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, Section II.A.1).

8.6.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from startup which is in excess of 30% opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4).

Compliance with these limitations shall be monitored by conducting opacity observations in accordance with EPA Reference Method 9 as follows:

8.6.3 **For propane-fired engine (pipeline receipt station emergency generator).** In the absence of credible evidence to the contrary, compliance with the opacity requirements will be presumed since only propane is permitted to be used as fuel for this engine. The permittee shall maintain records that verify that only propane is used as fuel in this engine.

8.6.4 **For diesel fuel-fired engines (emergency fire pump engines, P1 control room emergency generator and emergency air compressors).** Compliance with the opacity limitations shall be monitored by conducting opacity observations in accordance with EPA Reference Method 9 as follows:

8.6.4.1 Engine startup shall not exceed 30 minutes. An engine startup period of less than 30 minutes shall not require an opacity observation to monitor compliance with the opacity limit in Condition 8.6.2. A record shall be kept of the date and time the engine started and when it was shutdown.

8.6.4.2 A Method 9 opacity observation shall be conducted annually (calendar year period). Annual opacity observations for an individual engine shall be separated by a period of four (4) months.

If an engine is operated more than 250 hours in any calendar year period, a second opacity observation shall be conducted. If two opacity readings are conducted in the annual (calendar year) period, such readings shall be conducted at least thirty days apart.

8.6.4.3 If an engine is not operated during the annual (calendar year) period, then no opacity observation is required.

8.6.4.4 Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

8.6.4.5 All opacity observations shall be performed by an observer with current and valid Method 9 certification. Results of Method 9 readings and a copy of the certified Method 9 reader's certificate shall be kept on site and made available to the Division upon request.

8.7 The **emergency air compressor engines** are subject to the requirements in 40 CFR Part 60 Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines", as adopted by reference in Colorado Regulation No. 6, Part A, as follows:

The requirements below reflect the rule language in 40 CFR Part 60 Subpart IIII as of the latest revisions to 40 CFR Part 60 Subpart IIII published in the Federal Register on November 13, 2019.

However, if revisions to this Subpart are promulgated at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60 Subpart IIII.

The D. C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements allowing emergency engines to operate for limited hours for demand response. Upon issuance of the mandate § 60.4211(f)(2)(ii)-(iii) (Conditions 8.7.8.2.b and 8.7.8.2.c) have no legal effect. Operation of emergency engines is limited to emergency situations specified in 60.4211(f)(1) (Condition 8.7.8.1); maintenance checks and readiness testing for a limited number of hours per year as specified in 60.4211(f)(2)(i) (Condition 8.7.8.2.a); and certain non-emergency situations for a limited number of hours per year as specified in 60.4211(f)(3) (Condition 8.7.8.3). See EPA memorandum dated April 15, 2016 regarding "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" for more information.

It should be noted that additional revisions to the requirements in 40 CFR Part 60 Subpart IIII are expected to be made in response to issues related to the vacatur or requirements associated with the allowable hours of operation provisions for emergency engines discussed in the above paragraph. If such revisions are finalized prior to issuance of the permit, they will be included in the permit.

What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine? (§ 60.4205)

8.7.1 Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. (§ 60.4205(b))

Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section. (§ 60.4202(a))

For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007. (§ 60.4202(a)(2))

The specific emission limitations in 40 CFR 89.112 that apply to the **emergency air compressor engines** are as follows:

Tier 3 requirements for Model Engines 225 ≤ kw < 450 kW		
Emission Standards (g/kW-hr)		
NMHC + NOX	CO	PM
4.0	3.5	0.2

Note that the smoke standards in 40 CFR 89.113 do not apply because these engines are constant speed engines (89.113(c)(3))

How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine? (§60.4206)

8.7.2 Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart? (§60.4207)

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

The fuel limitations in 80.510(b) are: sulfur content of 15 ppm maximum for NR diesel fuel and 500 ppm maximum for LM diesel fuel and a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

Compliance with the fuel limitations shall be monitored by sampling and analyzing each shipment of diesel fuel to determine the sulfur and cetane and/or aromatic content using appropriate ASTM methods, or equivalent if approved in advance by the Division. In lieu of sampling, vendor data may be used to verify that the diesel fuel delivered meets the sulfur and cetane and/or aromatic requirements.

What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine? (§60.4209)

8.7.4 If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine. (§ 60.4209(a))

8.7.5 If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached. (§60.4209(b))

What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine? (§60.4211)

8.7.6 If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under §60.4211(g) (Condition 8.7.9): (§60.4211(a))

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

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

8.7.6.3 Meet the requirements of 40 CFR part 1068, as they apply to you. (§60.4211(a)(1) – (3))

8.7.7 If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted under §60.4211(g) (Condition 8.7.9). (§60.4211(c))

8.7.8 If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in 60.4211(f)(1) through (3) (Conditions 8.7.8.1 through 8.7.8.3). In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 60.4211(f)(1) through (3) (Conditions 8.7.8.1 through 8.7.8.3), is prohibited. If you do not operate the engine according to the requirements in 60.4211(f)(1) through (3) (Conditions 8.7.8.1 through 8.7.8.3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. (§ 60.4211(f))

8.7.8.1 There is no time limit on the use of emergency stationary ICE in emergency situations. (60.4211(f)(1))

8.7.8.2 You may operate your emergency stationary ICE for any combination of the purposes specified in 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2). (60.4211(f)(2))

a. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (60.4211(f)(2)(i))

b. Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. (60.4211(f)(2)(ii))

c. Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. (60.4211(f)(2)(iii))

8.7.8.3 Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in 60.4211(f)(2) (Condition 8.7.8.2). Except as provided in 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (60.4211(f)(3))

a. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the requirements in 60.4211(f)(3)(i)(A) through (E) are met. (60.4211(f)(3)(i))

8.7.9 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 as specified in § 60.4211(g)(1) through (3), as applicable. (§ 60.4211(g))

What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine? (§60.4214)

8.7.10 If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. (§ 60.4214(b))

8.7.11 If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached. (§60.4214(c))

What parts of the general provisions apply to me? (§60.4218)

8.7.12 Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Note that the relevant general provisions applicable to this engine are specified in Condition 56.3 of this permit.

8.8 The **emergency air compressor engines** are subject to the requirements in 40 CFR Part 63 Subpart ZZZZ, "National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines", as follows:

8.8.1 An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f). (§63.6590(b)(1))

Each emergency air compressor engine meets the following criteria: The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii). (63.6590(b)(1)(i))

8.8.2 If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

As specified in 63.6645(c), the initial notification must be submitted no later than 120 days after the engine becomes subject to this subpart (i.e., upon startup). The emergency air compressors commenced operation on January 28, 2020.

8.9 The **pipeline receipt station emergency generator** is subject to the requirements in 40 CFR Part 60 Subpart JJJJ, "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines", as adopted by reference in Colorado Regulation No. 6, Part A, as follows:

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60 Subpart JJJJ published in the Federal Register on June 29, 2021. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60 Subpart JJJJ.

The D. C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements allowing emergency engines to operate for limited hours for demand response. Upon issuance of the mandate § 60.4243(d)(2)(ii)-(iii) (Conditions 8.9.6.2.b and 8.9.6.2.c) have no legal effect. Operation of emergency engines is limited to emergency situations specified in 60.4243(d)(1) (Condition 8.9.6.1); maintenance checks and readiness testing for a limited number of hours per year as specified in 60.4243(d)(2)(i) (Condition 8.9.6.2.a); and certain non-emergency situations for a limited number of hours per year as specified in 60.4243(d)(3) (Condition 8.9.6.3). See EPA memorandum dated April 15, 2016 regarding "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" for more information.

It should be noted that additional revisions to the requirements in 40 CFR Part 60 Subpart JJJJ are expected to be made in response to issues related to the vacatur or requirements associated with the allowable hours of operation provisions for emergency engines discussed in the above paragraph. If such revisions are finalized prior to issuance of the permit, they will be included in the permit.

These requirements have not been adopted into Colorado Regulation No. 6, Part A as of the date of this permit issuance **July 9, 2024**, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable and the emergency engine may be subject to APEN reporting and minor source permitting requirements.

What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine? (§60.4233)

8.9.1 Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in §60.4231(c) for their stationary SI ICE. (§60.4233(c))

Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130

HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. (§60.4231(c), includes just the language relevant to the engine)

The specific emission limitations in 40 CFR part 1048 that apply to this engine are shown in the table below:

Pollutant	Emission Limitation
General Duty Standards	
HC + NO_X	2.7 g/kW-hr
CO	4.0 g/kW-hr
Field Testing Standards	
HC + NO_X	3.8 g/kW-hr
CO	6.5 g/kW-hr

8.9.2 Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section. (§60.4233(h))

How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine? (§ 60.4234)

8.9.3 Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine. (§60.4234)

What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine? (§60.4237)

8.9.4 Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter. (§60.4237(b))

What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine? (§ 60.4243)

8.9.5 If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in §60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in §60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section. (§60.4243(a))

8.9.5.1 If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance. (§60.4243(a)(1))

8.9.5.2 If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate. (§60.4243(a)(2)) Note that (a)(2)(ii) is applicable, so only that paragraph was included.

a. If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, 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 within 1 year of engine startup to demonstrate compliance. (§60.4243(a)(2)(ii))

8.9.6 If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in Conditions 8.9.6.1 through 8.9.6.3, is prohibited. If you do not operate the engine according to the requirements in Conditions 8.9.6.1 through 8.9.6.3, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. (§60.4243(d))

8.9.6.1 There is no time limit on the use of emergency stationary ICE in emergency situations. (§60.4243(d)(1))

8.9.6.2 You may operate your emergency stationary ICE for any combination of the purposes specified in Conditions 8.9.6.2.a through c of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by Condition 8.9.6.3 of this section counts as part of the 100 hours per calendar year allowed by this Condition 8.9.6.2. (§60.4243(d)(2))

a. Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (§60.4243(d)(2)(i))

b. Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. (§60.4243(d)(2)(ii))

c. Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. (§60.4243(d)(2)(iii))

8.9.6.3 Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in Condition 8.9.6.2. Except as provided in Condition 8.9.6.3.a, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (§60.4243(d)(3))

a. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the requirements in §62.4243(d)(3)(i)(A) through E) are met. (§60.4243(d)(3)(i))

8.9.7 If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine undergoes rebuild, major repair or maintenance. Engine rebuilding means to overhaul an engine or to otherwise perform extensive service on the engine (or on a portion of the engine or engine system). For the purpose of this 60.4343(f), perform extensive service means to disassemble the engine (or portion of the engine or engine system), inspect and/or replace many of the parts, and reassemble the engine (or portion of the engine or engine system) in such a manner that significantly increases the service life of the resultant engine. (§60.4243(f))

What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine? (§ 60.4245)

8.9.8 Owners and operators of all stationary SI ICE must keep records of the following information:

8.9.8.1 All notifications submitted to comply with this subpart and all documentation supporting any notification. (§60.4245(a)(1))

8.9.8.2 Maintenance conducted on the engine. (§60.4245(a)(2))

8.9.8.3 If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable. (§60.4245(a)(3))

8.9.8.4 If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards. (§60.4245(a)(4))

8.9.9 For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator 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. (§60.4245(b), includes just the language relevant to the engine)

8.9.10 If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in Conditions 8.9.6.2.b and c or that operates for the purposes specified in Condition 8.9.6.3.a, you must submit an annual report according to the requirements in §60.4245(e)(1) through (3). (§60.4245(e))

What parts of the General Provisions apply to me? (§ 60.4246)

8.9.11 Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you. (§ 60.4246) These requirements include but are not limited to the following:

8.9.11.1 The circumvention requirements in §60.12 (Condition 56.3)

8.10 The **pipeline receipt station emergency generator** must be fired with purchased propane from a dedicated line and isolated from the refinery's fuel gas system. Records of propane purchases shall be maintained and made available to the Division upon request.

9. Solvent Usage

D001 - Cold Cleaner Solvent Degreaser

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Work Practice Standards	9.1			Certification	Annually
Transfer and Storage of Waste Solvents	9.2			Certification	Annually

Note that these emission units are exempt from the APEN reporting requirements in Regulation No. 3, Part A and the construction permit requirements in Regulation No. 3, Part B.

D004 - Industrial Solvent Cleaning Operations

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Transfer and Storage of Waste Solvents	9.2			Certification	Annually
Industrial Solvent Cleaning Operations	9.3	Requirements apply if actual, uncontrolled VOC emissions from industrial solvent cleaning operations exceed 3 tons in a calendar year		Applicability	
				Recordkeeping and Calculation	Annual (Calendar Year)
				See Colorado Regulation No. 25, Part B, Section II.E (Condition 9.3)	
APEN Reporting	9.4			See Condition 9.4	

9.1 The design and operation of these cold cleaner solvent degreasers shall meet the standards defined in Colorado Regulation 25, Part B, Section II.B, set forth below. The permittee's operating procedures for solvent cleaning shall include these requirements.

<u>Control Equipment (Regulation No. 25, Part B, Section II.B.1)</u>

9.1.1 Covers (Section II.B.1.a)

9.1.1.1 All cold-cleaners shall have a properly fitting cover. (II.B.1.a.(i))

9.1.1.2 Covers shall be designed to be easily operable with one hand under any of the conditions set forth in Section II.B.1.b.(ii)(A) through (C). (II.B.1.a.(ii))

9.1.2 Drainage Facility (Section II.B.1.b)

9.1.2.1 All cold-cleaners shall have a drainage facility that captures the drained liquid solvent from the cleaned parts. (Section II.B.1.b.(i))

9.1.2.2 For cold-cleaners using solvent which has a vapor pressure greater than 32 torr (0.62 psia) measured at 38 ºC (100 ºF) the drainage facility shall meet the requirements in either Section II.B.1.b.(ii)(A) or (B). (Section II.B.1.b.(ii))

9.1.3 A permanent, clearly visible sign shall be mounted on or next to the cold-cleaner. The sign shall list the operating requirements. (Section II.B.1.c)

9.1.4 Solvent spray apparatus shall not have a splashing, fine atomizing, or shower type action but rather should produce a solid, cohesive stream. Solvent spray shall be used at a pressure that does not cause excessive splashing. For solvents with a true vapor pressure above 32 torr (0.62 psia) at 38 ºC (100 ºF), or, for solvents heated above 50 ºC (120 ºF), one of the techniques specified in Section II.B.1.d.(i) or (ii) shall be used (Section II.B.1.d)

Operating Requirements (Regulation No. 25, Part B, Section II.B.2)

9.1.5 The cold-cleaner cover shall be closed whenever parts are not being handled within the cleaner confines. (Section II.B.2.a)

9.1.6 Cleaned parts shall be drained for at least 15 seconds and/or until dripping ceases. Any pools of solvent shall be tipped out on the clean part back into the tank. (Section II.B.2.b)

9.2 The transfer and storage of waste and used solvents from the cold cleaner solvent degreasers are subject to the following requirements (Colorado Regulation No. 25, Part B, Section II.A.3 and 4):

9.2.1 In any disposal or transfer of waste or used solvent, at least 80 percent by weight of the solvent/waste liquid shall be retained (i.e., no more than 20 percent of the liquid solvent/solute mixture shall evaporate or otherwise be lost during transfers).

9.2.2 Waste or used solvents shall be stored in closed containers unless otherwise required by law.

The permittee's operating procedures for the solvent vats and contracts and/or agreements with contractors to service these vats shall include these requirements.

9.3 Industrial solvent cleaning operations shall meet the requirements in Colorado Regulation No. 25, Part B, Section II.E set forth below in any calendar year when actual, uncontrolled VOC emissions from industrial solvent cleaning operations exceed the level specified in Section II.E.1 (Condition 9.3.1).

Control Requirements (Regulation No. 25, Part B, Section II.E.1)

9.3.1 The owner or operator of an industrial cleaning solvent operation with total combined uncontrolled actual VOC emissions equal to or greater than three (3) tons per calendar year (excluding VOC emissions from solvents used for cleaning operations that are exempt under Section II.E.4.) must (Section II.E.1):

9.3.1.1 Limit the VOC content of cleaning solvents to less than or equal to 0.42 lb of VOC/gal (50 grams VOC/liter) (Section II.E.1.a); or

9.3.1.2 Limit the composite partial vapor pressure of the cleaning solvent to 8 millimeters of mercury (mmHg) at 20 degrees Celsius (68 degrees Fahrenheit) (Section II.E.1.b); or

9.3.1.3 Reduce VOC emissions with an emission control system having a control efficiency of 90% or greater. (Section II.E.1.c)

Work Practice Requirements (Regulation No. 25, Part B, Section II.E.2)

9.3.2 The owner or operator of an industrial cleaning solvent operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

9.3.2.1 Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere (Section II.E.2.a);

9.3.2.2 Properly dispose of used solvent and shop towels (Section II.E.2.b); and

9.3.2.3 Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintaining cleaning equipment to be leak free. (Section II.E.2.c)

Monitoring, Recordkeeping and Reporting Requirements (Regulation No. 25, Part B, Section II.E.3)

9.3.3 The owner or operator of an industrial cleaning solvent operation must keep the following records for two (2) years and make them available for inspection by the Division upon request: (Section II.E.3.a) In lieu of retaining records for two years, records shall be kept as required by Section IV, Condition 22.b and c.

9.3.3.1 If applicable, records demonstrating that a listed exemption to this Section II.E. applies. (Section II.E.3.a.(i))

9.3.3.2 If applicable, monthly records such as safety data sheets or other analytical data from the industrial cleaning solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent cleaning operations to demonstrate compliance with the control requirements in Sections II.E.1.a. and II.E.1.b. (Section II.E.3.a.(ii))

9.3.3.3 If applicable, monthly records sufficient to demonstrate compliance with the control requirement in Section II.E.1.c. (Section II.E.3.a.(iii))

9.3.3.4 Records of calendar year VOC emission estimates demonstrating whether the industrial cleaning solvent operation meets or exceeds the applicability threshold in Section II.E.1. (Section II.E.3.a.(iv))

9.3.4 Compliance with the control requirements in Section II.E.1. must be demonstrated using one of the following methods as applicable:

9.3.4.1 Safety data sheets or other analytical data from the industrial cleaning solvent manufacturer to demonstrate compliance with Sections II.E.1.a and II.E.1.b. (Section II.E.3.b.(i));

9.3.4.2 A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with Section II.E.1.c. (Section II.E.3.b.(ii)); or

9.3.4.3 A performance test conducted during representative operations using one of the methods in Section II.E.3.b.(iii)(A) or (B), as applicable (Section II.E.3.b.(iii))

Exemptions (Regulation No. 25, Part B, Section II.E.4)

9.3.5 Industrial cleaning solvent operations are not subject to Section II.E. if they are subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT. (Section II.E.4.a)

As of the date of this permit issuance **July 9, 2024**, no exemptions have been identified for industrial solvent cleaning operations at this facility.

9.3.6 The VOC control requirements in Section II.E.1. do not apply to: the activities listed in Section II.E.4.b.(i) through (xi). (Section II.E.4.b)

9.4 In the event that actual, uncontrolled VOC emissions from industrial solvent cleaning operations exceed the level specified in Condition 9.3.1 (3 tons per year), an APEN shall be filed for industrial solvent cleaning operations. The APEN shall cover emissions from any industrial solvent cleaning operation that is not already reported on an APEN (e.g. solvents routed to a flare of the tank degassing thermal oxidizer).

10. Cooling Towers – Plant 1: Y1, Y3 and Y4 and Plant 3: Y2

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Water Circulated	10.1	Y1: 21,549,600,000 gallons/year Y2: 1,392,840,000 gallons/year Y3: 3,679,000,000 gallons/year Y4: 7,884,000,000 gallons/year		Flow Monitors and Recordkeeping	Monthly
Total Dissolved Solids and Strippable Hydrocarbons Analysis	10.2			See Condition 10.2	
Y1 Cooling Tower: Hours of Operation	10.3			Recordkeeping	Monthly
PM	10.4	Y1: 13.5 tons/year Y4: 4.9 tons/year	See Condition 10.4	Recordkeeping and Calculation	Monthly
PM_{10}		Y1: 13.5 tons/year Y4: 4.9 tons/year			
VOC		Y1: 34.6 tons/year Y2: 2.2 tons/year Y3: 1.85 tons/year Y4: 12.4 tons/year			
Opacity	10.5	Not to Exceed 20%		See Condition 10.5.	
MACT	10.6	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Y2 and Y3: PM and PM_{10} Annual Emissions	10.7			Recordkeeping and Calculation	Annually
Y3: Restrictions on Relaxing Emission Limitations	10.8	See Condition 10.8		Certification	Annually

10.1 Water Circulated through the **Cooling Towers Y1, Y2, Y3 & Y4)** shall not exceed the above limitations. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Section I.A.7 and Part C, Section III.B.7 based on the requested throughput on the APENs submitted June 10, 2015 and red-lined July 14, 2015) The quantity of water circulated **through each tower** shall be monitored and recorded monthly. **For Y3 and Y4**, the monthly quantity of water circulated shall be determined using flow meters. **For Y1 and Y2**, the monthly quantity of water circulated shall be determined using the maximum circulation rate (2,460,000 gal/hr for Y1 and 159,000 gal/hr for Y2) multiplied by hours of operation (as required by Condition 10.3). The monthly quantities of water circulated through each tower shall be used in separate twelve month rolling totals to monitor compliance with the annual limitations. Each month a new twelve month total shall be estimated using the previous twelve months data.

10.2 The total dissolved solids and strippable hydrocarbons from the **Plant 1 (Y1, Y3 & Y4) and Plant 3 (Y2) Cooling Towers** shall be determined as follows:

10.2.1 Total dissolved solids shall be determined monthly using the measured monthly specific conductivity multiplied by 0.7. A copy of the procedures used to obtain the specific conductivity measurement shall be maintained and made available to the Division upon request. The monthly total dissolved solids shall be used as follows:

10.2.1.1 The monthly total dissolved solids for **Y1 and Y4** shall be used to calculate monthly emissions as required by Condition 10.4.

10.2.1.2 The monthly total dissolved solids for **Y2 and Y3** shall be used to calculate a calendar year annual average.

10.2.2 Total strippable hydrocarbons shall be determined using the methods and frequency specified in Condition 53.56. The total strippable hydrocarbons shall be used to calculate VOC emissions as required by Condition 10.4.

10.3 Hours of operation from the **Y1 and Y2 Cooling Towers** shall be monitored and recorded monthly. Hours of operation shall be used to determine the monthly quantity of water circulated (as required by Condition 10.1).

10.4 Particulate Matter (PM and PM_{10}) and Volatile Organic Compound (VOC) emissions from the **Plant 1 (Y1, Y3 & Y4) and Plant 3 (Y2) Cooling Towers** shall not exceed the above limitations. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Section I.A.7 and Part C, Section III.B.7 based on the emissions requested on the APENs submitted on June 10, 2015 and red-lined July 14, 2015 for towers Y-1, Y-2 and Y-4 and July 18, 2018 for tower Y-3) Monthly emissions **from each cooling tower** shall be calculated by the end of the subsequent month using the equations and information below:

PM and PM_{10} emissions – Y1 and Y4 only.

$PM = PM_{10}$ (tons/mo) = Q x d x % drift x total dissolved solids/2000 lbs/ton

Where: Q = water circulated, gal/mo
d = density of water, lbs/gal = 8.34 lb/gal
% drift = Y1 and Y4 - 0.005%, Y3 - 0.001%
Total dissolved solids = total dissolved solids, in ppm (lbs solids/10^6 lbs water) - to be determined by Condition 10.2. Emissions shall be calculated using monthly total dissolved solids.

VOC emissions – all towers

VOC equations are from “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003”

$$\text{VOC (ppmw)} = \frac{\text{MW x (P x 0.03342 atm/inHg) x b x c}}{\text{R x (T + 273) x a}}$$

Where: a = sample water flow rate (ml/min)

b = stripping air flow rate (ml/min)
c = concentration of compound in stripped air (ppmv)
M= molecular weight of methane (16.04 g/mole)
P = pressure in the stripping chamber (inHg), atmospheric = 27.8 inHg
R = ideal gas constant (82.054 ml-atm/mole-K)
T = stripping chamber temperature (°C)

VOC (tons/month) = C x Q x d/2000 lb/ton

Where: C = concentration of air strippable compound in the water matrix (ppmw), determined by above equation
Q = water circulated, gal/mo
d = density of water, lbs/gal = 8.34 lb/gal

Monthly emissions from each cooling tower shall be used in separate twelve month rolling totals to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be estimated using the previous twelve months data.

10.5 Opacity of emissions **from each cooling tower** shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). In the absence of credible evidence to the contrary, compliance with the opacity standard shall be presumed, provided the drift eliminators on the towers are maintained and operated in accordance with manufacturers' requirements and good engineering practices.

10.6 The heat exchange systems (cooling tower and all petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in 40 CFR Part 63 Subpart CC, serviced by that cooling tower) are subject to the requirements in 40 CFR Part 63 Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as set forth in Condition 53 of this permit.

10.7 For purposes of APEN reporting annual emissions of PM and PM_{10} from the Y2 and Y3 Cooling Towers shall be calculated on an annual (calendar year) basis using the equation set forth in Condition 10.4, the average total solids concentrations (as required by Condition 10.2.1.2) and the annual (calendar year) throughput in Condition 10.1. Annual emissions calculations shall be conducted by February 1 of the subsequent calendar year. If annual (calendar year) emissions from either Y2 or Y3 exceed the APEN de minimis level, then a minor modification application shall be submitted within 30 days of completing the emissions calculations to include emissions limitations in the permit.

10.8 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section VI.B.4).

Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.10 (Y-3 Cooling Tower), as well Sections II.4 (Tanks T-52, T-774 and T-777), II.13 (Boilers B-6 and B-8), II.20 (TGU Incinerator H-25), II.21 (Process

Heaters H-1716 and H-1717), II.27 (Process Heater H-2101) and II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H2 Plant Drain Systems). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants.

11. Process Heater H-6 (rated at 14.4 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	11.1		7.45×10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
	11.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	11.1		7.45×10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	11.1	1.87 tons/year	See Condition 11.1		
	11.3	NSPS Subpart J Requirement: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		Continuous Monitoring System	Continuous
	11.4	0.3 lb SO_2/bbl/day of oil processed	See Condiition 11.4	Recordkeeping and Calculation	Daily Monthly
NO_x	11.1	3.09 tons/year	0.049 lbs/MMBtu	Recordkeeping and Calculation	Monthly
VOC			5.39×10^{-3} lbs/MMBtu		
CO		5.17 tons/year	0.082 lbs/MMBtu		
Heat Input	11.5	126,144,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	11.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	11.7	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
NSPS General Provisions	11.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60, Subpart A (Condition 56)	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

11.1 Emissions of air pollutants shall not exceed the limits listed in the above table. (As provided for in accordance with Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to set emissions limits at the levels included on the APEN submitted October 4, 2017) **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above table (from AP-42, Section 1.4. dated 7/98, Tables 1.4-1 and 1.4-2, for boilers < 100 MMBtu/hr with low NO_X burners, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a) and the monthly fuel consumption (as required by Condition 11.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/2000 (lbs/ton)

For SO_2, daily emissions shall be calculated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 11.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

1 ppm H_2S = 0.169 lb SO_2/ 1,000 Mscf as shown in the equation below:

1 ppm H_2S = (1 scf H_2S/10^6 scf FG) x lb-mole H_2S/379 scf H_2S x lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2 x 10^6 scf FG/1,000 Mscf FG = 0.169 lb SO_2/1,000 Mscf FG

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

Note that PM, PM_{10} and VOC emission limits are not included in the permit for process heater H-6 but emissions from these pollutants shall be calculated and reported on revised APENs submitted for the unit.

11.2 This source is subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

11.3 This source is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirement that heaters are subject to NSPS Subpart J. Consent Decree (H-01-4430), paragraph 69)

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

11.4 Sulfur dioxide emissions from this source shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions shall be calculated as set forth in Condition 11.1 of this permit.

11.5 The heat input (Btu per year, higher heating value (HHV)) shall not exceed 126,144,000,000 Btu per year. (As provided for in accordance with Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to set throughput limits at the levels included on the APEN submitted October 4, 2017) Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use for this unit monthly. Monthly quantities of fuel used shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

11.6 This source is subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

11.7 This heater is subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

11.8 This heater is subject to the NSPS general provisions in 40 CFR part 60 Subpart A as set forth in Condition 56 of this permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate Consent Decree (H-01-4430) requirement that heaters are subject NSPS Subpart A. Consent Decree (H-01-4430), paragraph 69)

12. Process Heaters Without Annual Emission Limitations – H-10 (rated at 34.02 MMBtu/hr), H-11 (Rated at 29.76 MMBtu/hr), H-16 (Rated at 6.0 MMBtu/hr), H-18 (Rated at 6.0 MMBtu/hr), H-20 (Rated at 14.0 MMBtu/hr), H-21 (Rated at 24 MMBtu/yr), H-22 (Rated at 59.76 MMBtu/hr) and H-27 (Rated at 76.48 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	12.1		7.6 lb/MMscf	Recordkeeping and Calculation	Annually
	12.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	12.1		7.6 lb/MMscf	Recordkeeping and Calculation	Annually
SO_2	12.1		See Condition 12.1		Daily, Annually
	12.3	<u>NSPS Subpart J Requirement:</u> Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		Continuous Emission Monitor	Continuous
	12.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 12.4	Recordkeeping and Calculation	Daily Monthly
NO_X	12.1		100 lb/MMscf	Recordkeeping and Calculation	Annually
VOC			5.5 lb/MMscf		
CO			84 lb/MMscf		
Fuel Use	12.5			Recordkeeping	Daily Annually
Opacity	12.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
All Except H-21: MACT	12.7	**For all but H-16 & H-18:** Annual Tune-Up **For H-16 & H-18:** Tune-Up Every Two Years One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
NSPS General Provisions	12.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
RACT	12.9	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	12.10	Combustion Process Adjustment Requirements		See Condition 73	
Regional Haze Requirements **– State-Only**	12.11	H-11: NO_X – 12.78 tons/yr H-27: NO_X = 32.84 tons/yr	100 lb/MMscf	Recordkeeping and Calculation	Monthly

Heater H-21 is exempt from the APEN reporting requirements, as long as actual, uncontrolled emissions do not exceed the APEN de minimis level.

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

12.1 These emission units are subject to the APEN reporting and annual emission fee requirements. **For all pollutants except SO_2**, annual emissions **from each heater or boiler** shall be calculated using the emission factors in the above table (PM., PM_{10} and VOC from AP-42, Section 1.4, dated 7/98, Table 1.4-2 and NO_X and CO from AP-42, Section 1.4, dated 7/98, Table 1.4-1, boilers < 100 MMBtu/hr, uncontrolled. AP-42 emission factors converted to lb/MMBtu using a heat content of 1020 Btu/scf per footnote a) and actual fuel usage (as required by Condition 12.5) in the following equation:

Emissions (Tons/year) = [EF (lbs/MMscf) x fuel usage (MMscf/year]/2000 (lbs/ton)

For SO_2, daily emissions shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 12.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions, monthly SO_2 emissions shall be summed to determine annual SO_2 emissions.

12.2 These sources are subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

12.3 These sources are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit. (As provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to include Consent Decree (H-01-4430) requirement that heaters are subject to NSPS Subpart J. Consent Decree (H-01-4430), paragraph 69)

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

12.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from **each heater** shall be calculated as set forth in Condition 12.1 of this permit.

12.5 Refinery fuel gas will be monitored as set forth in Condition 58 of this permit. Records will be made available for inspection upon request (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Fuel use for each unit will be monitored and recorded annually.

12.6 These sources are subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

12.7 **With the exception of H-21**, these sources are subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

H-21 does not meet the definition of a process heater in §63.7575 since the combustion gases from H-21 come into direct contact with the process materials of the FCCU regenerator., therefore, H-21 is not subject to the requirements in Subpart DDDDD.

12.8 These sources are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit. (As provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7, III.B.7 to include Consent Decree (H-01-4430) requirement that heaters are subject to NSPS Subpart A. Consent Decree (H-01-4430), paragraph 69)

12.9 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, these emissions subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

Note that the exemption in Colorado Regulation No. 26, Part B, Section II.A.d.f (Condition 72.1.3) does not apply until approval of the adopted by the AQCC on December 17, 2021 into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

12.10 These emission units are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each heater's actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

12.11 **State-Only Requirement. Heaters H-11 and H-27** are subject to the requirements in Colorado Regulation No. 23, "Regional Haze Limits", as follows:

Note that the language below is from Colorado Regulation No. 23, adopted by the Colorado Air Quality Control Commission (AQCC) on December 17, 2021 (effective January 30, 2022). However, if revisions to Colorado Regulation No. 23 are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Colorado Regulation No. 23.

12.11.1 NO_X emissions shall not exceed the following limitations (Colorado Regulation No. 23, Section IV.F.3):

12.11.1.1 For H-11: 12.78 tons/yr, on a 12-month rolling total

12.11.1.2 For H-17: 32.84 tons/yr, on a 12-month rolling total

12.11.2 Compliance with the emission limits in Section IV.F.3. (Condition 12.11.1) must be determined by recording fuel consumption and calculating monthly emissions using the emission factors in the following table. Monthly emissions must be calculated by the end of the subsequent month. Monthly emissions must be used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve-month total must be calculated using the previous twelve months of data. The owner/operator must calculate emissions in the applicable units. (Colorado Regulation No. 23, Section V.A.2.e.(i))

Process Heater	Emission Factor
H-11, H-27	100 lb/MMscf

13. Process Boilers B6 (Rated at 111.0 MMBtu/hr) and B8 (rated at 161.0 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	13.1	B6: 3.59 tons/year B8: 5.20 tons/year	7.45 x 10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
	13.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	13.1	B6: 3.59 tons/year B8: 5.20 tons/year	7.45 x 10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	13.1	B6: 12.70 tons/year B8: 18.40 tons/year	See Condition 13.1.4		
	13.3	NSPS Subpart J Requirement: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		Continuous Monitoring System	Continuously
	13.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 13.4	Recordkeeping and Calculation	Daily Monthly
NO_X	13.1	B6: 19.45 tons/year B8: 28.21 tons/year	CEMS	Continuous Emission Monitoring System	Continuous
	13.7	0.040 lb/MMBtu based on 365 day rolling average			
VOC	13.1	B6: 2.60 tons/year B8: 3.77 tons/year	5.39 x 10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
CO	13.1	B6: 19.45 tons/year B8: 28.21 tons/year	CEMS	Continuous Emission Monitoring System	Continuously
	13.8	0.060 lb/MMBtu based on 24 hour rolling average 0.040 lb/MMBtu based on 365 day rolling average During Turndown: 0.08 lb/MMBtu based on 7 day rolling average, in lieu of the 0.060 lb/MMBtu limit			
Fuel Use	13.5	B6: 972,360,000,000 Btu/year B8: 1,410,360,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	13.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
MACT	13.9	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
NSPS General Provisions	13.10	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
RACT	13.11	NO_X emissions not to exceed 0.2 lb/MMBtu, on a 30-day rolling average		Continuous Emission Monitoring System	Continuously
	13.12	Combustion Process Adjustment Requirements		See Condition 73	
Restrictions on Relaxing Emission Limitations	13.13	See Condition 13.13		Certification	Annually

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

13.1 Emissions of air pollutants shall not exceed the limits listed in the above table. (Colorado Construction Permits 02AD0326 and 02AD0327). Compliance with the annual limits shall be monitored as follows:

13.1.1 **For PM, PM_{10} and VOC**, compliance with the annual limitations shall be monitored by calculating monthly emissions **from each boiler** using the emission factors in the above table (from AP-42, Section 1.4. dated 7/98, Table 1.4-2, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a) and the monthly fuel consumption (as required by Condition 13.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/2000 (lbs/ton)

Monthly emissions **from each boiler** shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

13.1.2 For NO_X, compliance with the annual limits shall be monitored using the NO_X continuous emission monitoring system (CEMS) required by Condition 13.7 as follows:

For any hour is which fuel is fired in the boiler, the permittee shall program the data acquisition and handling system to calculate lb/hr of NO_X emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass NO_X emissions (in lb/hr) shall be calculated **for each boiler** using the following equation:

$$E_h = F_d \times C_d \times MW/385.3 \times 10^{-6} \times (20.9/(20.9 - \%O_2)) \times H_g$$

Where: E_h = mass emissions (lb/hr)

F_d = fuel factor, dry, scf/MMBtu (calculated from on-site analyzers)
C_d = NO_X concentration, dry basis, ppm
MW = NO_X molecular weight, 46.01 lb/mol
Q_d = volumetric flow rate, dry basis, scfm
$\%O_2$ = O_2 concentration, dry basis (from O_2 CEMS)
H_g = heat input rate (MMBtu/hr)

The resulting NO_X lb/hr value is then multiplied by the unit operating time for the boiler for that hour to produce a NO_X lbs value. The hourly NO_X mass emissions (lbs) shall be summed and divided by 2000 to determine monthly NO_X emissions (in tons).

Monthly emissions shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

13.1.3 For CO, compliance with the annual limits shall be monitored using the CO CEMS required by Condition 13.8, as follows:

For any hour is which fuel is fired in the boiler, the permittee shall program the data acquisition and handling system to calculate lb/hr of CO emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass CO emissions (in lb/hr) shall be calculated **for each boiler** using the following equation:

$$E_h = F_d \times C_d \times MW/385.3 \times 10^{-6} \times (20.9/(20.9 - \%O_2)) \times H_g$$

Where: E_h = mass emissions (lb/hr)
F_d = fuel factor, dry, scf/MMBtu (calculated from on-site analyzers)
C_d = CO concentration, dry basis, ppm
MW = CO molecular weight, 28 lb/mol
Q_d = volumetric flow rate, dry basis, scfm
$\%O_2$ = O_2 concentration, dry basis (from O_2 CEMS)
H_g = heat input rate (MMBtu/hr)

The resulting CO lb/hr value is then multiplied by the unit operating time for the boiler for that hour to produce a CO lbs value. Hourly CO mass emissions (lbs) shall be summed and divided by 2000 to determine monthly CO emissions (in tons).

Monthly emissions shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

13.1.4 **For SO_2**, daily emissions **from each boiler** shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 13.3) and the daily fuel consumption (as required by Condition 58)

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions. Monthly emissions **from each boiler** shall be used in a twelve-month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

13.2 These boilers are subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

13.3 These boilers are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit. (Colorado Construction Permits 02AD0326 and 02AD0326 and Consent Decree (H-01-4430), paragraph 69)

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

13.4 Sulfur dioxide emissions from these boilers shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from **each boiler** shall be calculated as set forth in Condition 13.1.4 of this permit.

13.5 Consumption of refinery fuel gas from these boilers shall not exceed the following:

Boiler B6: 972,360,000,000 Btu (HHV) per year. (Colorado Construction Permit 02AD0326)

Boiler B8: 1,410,360,000,000 Btu (HHV) per year (Colorado Construction Permit 02AD0327)

Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use for each boiler monthly. Monthly quantities of fuel used in each boiler shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

13.6 These boilers are subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

13.7 NO_X emissions **from each boiler** shall not exceed 0.040 lb NOx/MMBtu on a 365-day rolling average. (Colorado Construction Permits 02AD0326 and 02AD0327 and Consent Decree (H-01-4430), paragraph 55(d)) NO_X CEMS shall be used to monitor compliance with the annual (365-day rolling average basis) NO_X emissions limitations. The NO_X CEMS shall be certified, calibrated, maintained and operated in accordance with the requirements in Condition 59 of this permit. (Consent Decree (H-01-4430), paragraphs 55(d) and 64)

13.8 Upon installation of NO_X Controls at a specific heater or boiler, Suncor shall limit the CO emissions from that Controlled Heater and Boiler to 0.060 lb/MMBtu (HHV) on a 24-hour rolling average basis and 0.040 lb/MMBtu on a 365-day rolling average basis, except during Turndown Operations where Suncor shall limit CO emissions to 0.08 lb/MMBtu on a 7-day rolling average basis in lieu of the 0.060 lb/MMBtu CO limit. Turndown Operations shall be defined as a period when the specific heater or boiler is firing at a rate that is less than 30% of the heater or boilers maximum firing rate in MMBtu/hr. CO emissions during periods of startup, shutdown and malfunctions will not be used for determining compliance with the 24-hour or 7-day rolling average basis limits, provided Suncor implements good air pollution control practices to minimize emissions during such periods. If Suncor demonstrates that meeting these limits is not technically feasible, the Suncor may request and EPA may approve alternative limits. (Colorado Construction Permits 02AD0327 and 02AD0326 and Consent Decree (H-01-4430), paragraph 73(a), as modified under the provisions of Section I, Condition 1.3, to include full language from Consent Decree (H-01-4430), paragraph 73(a) per December 9, 2008 minor modification.)

Determination of whether good air pollution control practices are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

If Suncor requests and EPA approves alternative CO limits Suncor shall submit an application to modify this permit within 30 days of EPA's approval of alternative CO limits to incorporate the alternative CO limits into this permit.

CO CEMS shall be used to monitor compliance with the 24-hour and annual (365-day rolling average basis) CO emissions limitations. The CO CEMS shall be certified, calibrated, maintained and operated in accordance with the requirements in Condition 59 of this permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirement to use CO CEMS for boilers. Consent Decree (H-01-4430), paragraphs 55(d) and 64)

13.9 These boilers are subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

13.10 These boilers are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirement that boilers are subject to NSPS Subpart A. Consent Decree (H-01-4430), paragraph 69)

13.11 Boilers B6 and B8 are subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

13.12 These emission units are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each boiler's actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

13.13 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section VI.B.4).

Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.13 (Boilers B-6 and B-8), as well as Sections II.4 (Tanks T52, T774 and T777), II.10 (Y-3 Cooling Tower), II.20 (TGU Incinerator H-25), II.21 (Process Heaters H-1716 and H-1717), II.27 (Process Heater H-2101) and II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H_2 Plant Drain Systems). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants.

14. Process Heaters H-13 (Rated at 6.8 MMBtu/hr) and H-17 (Rated at 58.4 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	14.1	H-17: 1.89 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
	14.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	14.1	H-17: 1.89 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	14.1	H-13: 0.87 ton/year H-17: 7.45 tons/year	See Condition 14.1		
	14.3	<u>NSPS Subpart J Requirement:</u> Fuel gas shall not contain H_2S in excess of 0.10 gr/scf		Continuous Monitoring System	Continuous
	14.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 14.4	Recordkeeping and Calculation	Daily Monthly
NO_X	14.1	H-13: 2.89 tons/year H-17: 24.83 tons/year	0.098 lb/MMBtu	Recordkeeping and Calculation	Monthly
VOC		H-17: 1.37 tons/year	5.39 x 10^{-3} lb/MMBtu		
CO		H-13: 2.43 tons/year H-17: 20.86 tons/year	0.082 lb/MMBtu		
Fuel Use	14.5	H-13: 59,568,000,000 Btu/year H-17: 511,584,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	14.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	14.7	**H-13:** Tune-Up Every Two Years **H-17:** Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDDD (Condition 63)	
NSPS General Provisions	14.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
RACT	14.9	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	14.10	Combustion Process Adjustment Requirements		See Condition 73	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a

3-hour period (See 73 FR 35852).

14.1 Emissions of air pollutants shall not exceed the limits listed in the above table (Colorado Construction Permits 85AD027-1 (H-13) and 84AD027 (H-17) and Colorado Regulation No. 23, Section VI.F.3 for H-17 NO_X limit). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions **for each heater** using the emission factors in the above table (from AP-42, Section 1.4. dated 3/98, Tables 1.4-1 and 1.4-2, for boilers < 100 MMBtu/hr, uncontrolled, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a. For H-17 the NO_X emission factor is required by Regulation No. 23, Section V.A.2.3.(i) to be used in emission calculations.) and the monthly fuel consumption (as required by Condition 14.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/ 2000 (lbs/ton)

For SO_2, daily emissions shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 14.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

Note that PM, PM_{10} and VOC emission limits are not included in the permit for process heater H-13 but emissions from these pollutants shall be calculated and reported on revised APENs.

14.2 These sources are subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

14.3 These sources are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

14.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from **each heater** shall be calculated as set forth in Condition 14.1 of this permit.

14.5 Consumption of refinery fuel gas through these heaters shall not exceed the following:

H-13: 59,568,000,000 Btu (HHV) per year. (Colorado Construction Permit 85AD027-1)

H-17: 511,584,000,000 Btu (HHV) per year (Colorado Construction Permit 84AD027)

Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use for each unit monthly. Monthly quantities of fuel used shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

14.6 These sources are subject to the opacity limits set forth in Conditions 35.1, 35.2, and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

14.7 These heaters are subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

14.8 These heaters are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

14.9 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, these emissions subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

Note that the exemption in Colorado Regulation No. 26, Part B, Section II.A.d.f (Condition 72.1.3) does not apply until the requirements adopted by the AQCC on December 17, 2021 into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

14.10 These emission units are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each heater's actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

15. Process Heater H-19 (Rated at 29.18 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	15.1	0.96 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
	15.2	See Conditions 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	15.1	0.96 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	15.1	3.44 tons/year	See Condition 15.1		
	15.3	NSPS Subpart J Requirement: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		Continuous Monitoring System	Continuous
	15.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 15.4	Recordkeeping and Calculation	Daily Monthly
NO_x	15.1	15.34 tons/year	0.12 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC			5.39 x 10^{-3} lb/MMBtu		
CO		10.54 tons/year	0.082 lb/MMBtu		
Fuel Use	15.5	256,000,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	15.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	15.7	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
NSPS General Provisions	15.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
RACT	15.9	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	15.10	Combustion Process Adjustment Requirements		See Condition 73	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

15.1 Emissions of air pollutants shall not exceed the limits listed in the above table. (Colorado Construction Permit 90AD524, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to revise PM, PM_{10} and CO emissions as indicated in January 12, 2007 modification request). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above table (PM, PM_{10}, CO and VOC from AP-42, Section 1.4. dated 7/98, Tables 1.4-1 and 1.4-2, for boilers < 100 MMBtu/hr, uncontrolled, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a and NO_X from manufacturer) and the monthly fuel consumption (as required by Condition 15.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/ 2000 (lbs/ton)

For SO_2, daily emissions shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 15.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

Note that a VOC emission limit is not included in the permit for but VOC emissions shall be calculated and reported on revised APENs.

15.2 This source is subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

15.3 This source is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

15.4 Sulfur dioxide emissions from this source shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from this heater shall be calculated as set forth in Condition 15.1 of this permit.

15.5 Consumption of gaseous fuel in the heater shall not exceed 256,000,000,000 Btu (HHV) per year. (Colorado Construction Permit 90AD524) Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use for this unit monthly. Monthly quantities of fuel used shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

15.6 This source is subject to the opacity limits set forth in Conditions 35.1, 35.2, and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

15.7 This heater is subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

15.8 This heater is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

15.9 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, these emissions subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

15.10 These emission units are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on the heater’s actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

16. Process Heaters H-28 (Rated at 35.6 MMBtu/hr), H-29 (Rated at 35.6 MMBtu/hr), and H-30 (Rated at 17.4 MMBtu/hr) and Catalytic Reforming Unit P104

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	16.1	3.1 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
	16.2	See Conditions 36.1		Fuel Type	N/A
PM_{10}	16.1	3.1 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	16.1	10.5 tons/year	See Condition 16.1	Recordkeeping and Calculation	Monthly
	16.3	<u>NSPS Subpart J Requirement:</u> Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		Continuous Monitoring System	Continuous
	16.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 16.4	Recordkeeping and Calculation	Daily Monthly
NO_X	16.1	20.4 tons/year	0.049 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC		2.2 tons/year	5.39 x 10^{-3} lb/MMBtu		
CO		34.2 tons/year	0.082 lb/MMBtu		
Fuel Use	16.5	776,136,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	16.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
Reforming Unit[2]: MACT	16.7	<u>For initial catalyst depressuring and catalyst purging:</u> vent emissions to a flare <u>For coke burn-off and catalyst rejuvenation[3]:</u> daily HCl concentration not to exceed 27 ppmv		See 40 CFR Part 63 Subpart UUU (Condition 54)	
NSPS General Provisions	16.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
H-28, H-29 & H-30 - MACT	16.9	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
RACT	16.10	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
	16.11	Combustion Process Adjustment Requirements		See Condition 73	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

[2]Note that the catalytic reforming unit (CRU) is not generally a source of emissions. Emissions from the CRU during catalyst depressuring and purging operations are routed to the main plant flare (emissions are reported on that APEN. Fugitive VOC emissions from piping components are reported on the APEN for Emissions from the CRU during coke burn-off and catalyst rejuvenation are below the APEN de minimis level so an APEN for this activity is not required. However, the CRU is subject to requirements in 40 CFR Part 63 Subpart UUU and so it has been included in this permit.

[3]Note that the emission limitations is actually 30 ppmv HCl, on a dry basis, corrected to the 3% O_2. The above HCl concentration represents the operating limit established by the performance test.

16.1 Emissions of air pollutants **from heaters H-28, H-29 and H-30 combined** shall not exceed the limits listed in the above table (Colorado Construction Permit 86AD059 and Colorado Regulation No. 23, Section IV.F.3 for NO_X emissions). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions **from each heater** using the emission factors in the above table (from AP-42, Section 1.4. dated 7/98, Tables 1.4-1 and 1.4-2, for boilers < 100 MMBtu/hr, with low NO_X burners, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a. The NO_X emission factor is required by Colorado Regulation No. 23, Section V.A.2.3.(i) to be used in emission calculations.) and the monthly fuel consumption (as required by Condition 16.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/2000 (lbs/ton)

For SO_2, daily emissions **from each heater** shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 16.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions (daily monitoring is required to demonstrate compliance with Colorado Regulation No. 1, Section VI requirements, as described in Conditions 16.4 and 38.1).

Monthly emissions from each heater shall be calculated by the end of the subsequent month and summed to get combined monthly emissions from heaters H-28, H-29 and H-30. Combined monthly emissions from heaters H-28, H-29 and H-30 shall be used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

16.2 The heaters are subject to the particulate matter emission limit set forth in Condition 36.1 of this permit.

16.3 The heaters are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

16.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from each heater shall be calculated as set forth in Condition 16.1 of this permit.

16.5 Total consumption of refinery fuel gas **in heaters H-28, H-29 and H-30 combined**, shall not exceed 776,136,000,000 Btu (HHV) per year. (Colorado Construction Permit 86AD059, as modified under the provisions of Section I, Condition 1.3 to reflect the fuel limit (in Btu/yr) in the November 18, 1996 version of 86AD059) Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use **for each heater** monthly. Monthly quantities of fuel used for each heater shall be summed together to get combined monthly fuel use from heaters H-28, H-29 and H-30. The combined monthly fuel use from heaters H-28, H-29 and H-30 shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

16.6 These sources are subject to the opacity limits set forth in Conditions 35.1, 35.2, and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

16.7 The catalytic reforming unit (P104) is subject to 40 CFR Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, as set forth in Condition 54 of this permit.

16.8 These heaters are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

16.9 Heaters H-28, H-29 and H-30 are subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

16.10 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, these emissions subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

Note that the exemption in Colorado Regulation No. 26, Part B, Section II.A.d.f (Condition 72.1.3) does not apply until the requirements adopted by the AQCC on December 17, 2021 into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

16.11 These emission units are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each heater's actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

17. Process Heaters H-31 (Rated at 23.56 MMBtu/hr) and H-32 (Rated at 37.8 MMbtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring Method	Monitoring Interval
PM	17.1	3.68 tons/year	0.0137 lb/MMBtu	Recordkeeping and Calculation	Monthly
	17.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	17.1	3.68 tons/year	0.0137 lb/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	17.1	7.66 tons/year	See Condition 17.1		
	17.3	NSPS Subpart J Requirement: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average		Continuous Emission Monitor	Continuous
	17.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 17.4	Recordkeeping and Calculation	Daily Monthly
NO_X	17.1	32.25 tons/year	0.12 lb/MMBtu	Recordkeeping and Calculation	Monthly
VOC			5.39 x 10^{-3} lb/MMBtu		
CO		16.39 tons/year	0.0610 lb/MMBtu		
Fuel Use	17.5	537,520,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	17.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	17.7	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
NSPS General Provisions	17.8	See 40 CFR Part 60 Subpart A (Condition 56)		40 CFR Part 60 Subpart A (Condition 56)	
RACT	17.9	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	17.10	Combustion Process Adjustment Requirements		See Condition 73	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

17.1 Emissions of air pollutants **from heaters H-31 and H-32 combined** shall not exceed the limits listed in the above table (Colorado Construction Permit 91AD180-1). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions **from each heater** using the emission factors the above table (PM, PM_{10} and CO from construction permit, VOC from AP-42, Section 1.4. dated 7/93 (AP-42 Version 4, September 1985 with Supplements A-F (updated 7/93)), Tables 1.4-1 and 1.4-2, for boilers < 100 MMBtu/hr, uncontrolled, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a and NO_X from manufacturer) and the monthly fuel consumption (as required by Condition 17.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/2000 (lb/ton)

For SO_2, daily emissions **from each heater** shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 17.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions **from each heater** shall be calculated by the end of the subsequent month and summed together to get combined monthly emissions from heaters H-31 and H-32. Combined monthly emissions from heaters H-31 and H-32 shall be used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

Note that a VOC emission limit is not included in the permit for but VOC emissions from each heater shall be calculated, summed together and reported on revised APENs

17.2 These sources are subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

17.3 These sources are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

17.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from each heater shall be calculated as set forth in Condition 17.1 of this permit.

17.5 Consumption of gaseous fuel **in heaters H-31 and H-32 combined** shall not exceed 537,520,000,000 Btu (HHV) per year. (Colorado Construction Permit 91AD180-1) Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use for each heater monthly. Monthly quantities of fuel used for each heater shall be summed together to get combined monthly fuel use from heaters H-31 and H-32. The combined monthly fuel use from heaters H-31 and H-32 shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

17.6 These sources are subject to the opacity limits set forth in Conditions 35.1, 35.2, and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

17.7 These heaters are subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

17.8 These heaters are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

17.9 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, these emissions subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

17.10 These emission units are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each heater’s actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

18. Process Heaters H-33 (Rated at 7.680 lb/MMBtu) and H-37 (Rated at 57.25 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	18.1	**H-37:** 1.87 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
	18.2	See Conditions 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	18.1	**H-37:** 1.87 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	18.1	**H-37:** 7.45 tons/year	See Condition 18.1		
	18.3	NSPS Subpart J Requirements: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		Continuous Monitoring System	Continuous
	18.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 18.4	Recordkeeping and Calculation	Daily Monthly
NO_x	18.1	**H-33:** 1.72 tons/year	0.051 lb/MMBtu	Recordkeeping and Calculation	Monthly
		H-37: 10.41 tons/year	0.042 lb/MMBtu		
VOC		**H-37:** 1.35 tons/year	5.39 x 10^{-3} lb/MMBtu		
CO		**H-33:** 2.76 tons/year **H-37:** 20.56 tons/year	0.082 lb/MMBtu		
Fuel Use	18.5	**H-33:** 67,277,000,000 Btu/year **H-37:** 501,422,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	18.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	18.7	**H-33:** Tune-Up Every Two Years **H-37:** Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
NSPS General Provisions	18.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
H-37 Only: RACT	18.9	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	18.10	Combustion Process Adjustment Requirements		See Condition 73	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

18.1 Emissions of air pollutants shall not exceed the limits listed above (Colorado Construction Permit 91AD180-2, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to include emissions limitations requested on APENs submitted October 4, 2017 (for H-33) and October 13, 2020 (for H-37) and Colorado Regulation No. 23, Section IV.F.3 for H-37 NO_X emissions). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions **from each heater** using the emissions factors in the above table (PM, PM_{10}, NO_X (H-37 – w/o ULNB), CO and VOC: from AP-42, Section 1.4. dated 7/98, Tables 1.4-1 and 1.4-2, for boilers < 100 MMBtu/hr, uncontrolled, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a and NO_X: for H-33 based on performance tests conducted in 2002 and for H-37 based on NSPS Ja limit converted to lb/MMBtu. The NO_X emission factor for H-37 is required by Colorado Regulation No. 23, Section V.A.2.3.(i) to be used in emission calculations.) and the monthly fuel consumption (as required by Condition 18.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/2000 (lbs/ton)

For SO_2, daily emissions **from each heater** shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 18.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

Note that PM, PM_{10}, SO_2 and VOC emission limits are not included in the permit for process heater H-33 but emissions from these pollutants shall be calculated and reported on revised APENs submitted for the unit.

18.2 These heaters are subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

18.3 These heaters are subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

Compliance with the Subpart J fuel gas limit shall be monitored using a continuous H_2S monitoring system as specified in Condition 45.4.3.

18.4 Sulfur dioxide emissions from these heaters shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from each heater shall be calculated as set forth in Condition 17.1 of this permit.

18.5 Consumption of gaseous fuel in heaters shall not exceed 67,277,000,000 Btu (HHV) per year **for H-33** and 501,422,000,000 Btu (HHV) per year **for H-37**. (Colorado Construction Permit 91AD180-2, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to include throughput limitations requested on the APENs submitted October 4, 2017 (for H-33) and October 13, 2020 (for H-37)) Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use for each heater monthly. Monthly quantities of fuel used shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month new twelve month rolling totals shall be calculated using the previous twelve months data.

18.6 These heaters are subject to the opacity limits set forth in Conditions 35.1, 35.2, and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

18.7 These heaters are subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63of this permit.

18.8 These heaters are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

18.9 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, **Heater H-37** is subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

Note that the exemption in Colorado Regulation No. 26, Part B, Section II.A.d.f (Condition 72.1.3) does not apply until the requirements adopted by the AQCC on December 17, 2021 into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

18.10 **Heater H-37** is subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each heater's actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

19. Process Boiler B4 (Rated at 130.0 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring Method	Monitoring Interval
PM	19.1	4.98 tons/year	7.45 x 10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
	19.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	19.1	4.98 tons/year	7.45 x 10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	19.1	6.54 tons/year	See Condition 19.1.3		
	19.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 19.3	Recordkeeping and Calculation	Daily Monthly
NSPS Subpart Ja	19.4	Fuel gas shall not contain H_2S in excess of: 162 ppmv, on a 3-hour rolling average, and 60 ppmv, on a 365 day rolling average		Continuous Monitoring System	Continuously
NO_X	19.1	34.2 tons/year	CEMS	Continuous Emission Monitoring System	Continuously
NSPS Db	19.5	NO_X: 0.20 lb/MMBtu, on a 30-day rolling average			
		Annual Capacity Factor		Recordkeeping and Calculation	Daily Monthly
VOC	19.1	3.61 tons/year	5.39 x 10^{-3} lbs/MMBtu	Recordkeeping and Calculation	Monthly
CO		55.1 tons/year	0.082 lb/MMBtu		
Fuel Use	19.6	1,138,800 MMBtu/year		Recordkeeping	Daily Monthly
Opacity	19.7	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	19.8	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
NSPS General Provisions	19.9	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
RACT	19.10	Combustion Process Adjustment Requirements		See Condition 73	13.12
Regional Haze Requirements – **State-Only**	19.11	NO_X: - 0.06 lb/MMBtu, on a 30-day rolling average		Continuous Emission Monitoring System	Continuously

19.1 Emissions of air pollutants are subject to the following requirements:

19.1.1 PM, PM_{10}, CO and VOC emissions shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 20AD0714) Compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above table (from AP-42, Section 1.4. dated 7/98, Tables 1.4-1 and 1.4-2, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a) and the monthly fuel consumption (as required by Condition 13.5) in the equation below:

Emissions (Tons/Month) = [EF (lbs/MMBtu) x fuel usage (MMBtu/month)]/2000 (lbs/ton)

Monthly emissions shall be calculated by the end of the subsequent month and used in twelve-month rolling totals to monitor compliance with the annual limitations. Each month new twelve month totals shall be calculated using the previous twelve months data.

19.1.2 NO_X emissions shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 20AD0714) Compliance with the annual limits shall be monitored using the NO_X continuous emission monitoring system (CEMS) required by Condition 13.7 as follows:

For any hour is which fuel is fired in the boiler, the permittee shall program the data acquisition and handling system to calculate lb/hr of NO_X emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass NO_X emissions (in lb/hr) shall be calculated using the following equation:

$E_h = F_d \times C_d \times MW/385.3 \times 10^{-6} \times (20.9/(20.9 - \%O_2)) \times H_g$

Where: E_h = mass emissions (lb/hr)
F_d = fuel factor, dry, scf/MMBtu (calculated from on-site analyzers)
C_d = NO_X concentration, dry basis, ppm
MW = NO_X molecular weight, 46.01 lb/mol
Q_d = volumetric flow rate, dry basis, scfm
$\%O_2$ = O_2 concentration, dry basis (from O_2 CEMS)
H_g = heat input rate (MMBtu/hr)

The resulting NO_X lb/hr value is then multiplied by the unit operating time for the boiler for that hour to produce a NO_X lbs value. The hourly NO_X mass emissions (lbs) shall be summed and divided by 2000 to determine monthly NO_X emissions (in tons).

Monthly emissions shall be used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

19.1.3 SO_2 emissions shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 20AD0714) Compliance with the annual limitation shall be monitored by calculating SO_2 emissions daily as described below

Daily SO_2 emissions shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 19.4) and the daily fuel consumption (as required by Condition 58) (daily monitoring is required to demonstrate compliance with Colorado Regulation No. 1, Section VI requirements, as described in Conditions 19.3 and 38.1).

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions. Monthly emissions shall be used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

19.2 This boiler is subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

19.3 Sulfur dioxide emissions from this boiler shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from the boiler shall be calculated as set forth in Condition 19.1.3 of this permit.

19.4 This boiler is subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

Compliance with the Subpart Ja fuel gas limits shall be monitored using a continuous H_2S monitoring system as specified in Condition 46.14.

19.5 This boiler is subject to the requirements in 40 CFR Part 60 Subpart Db, “Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units”, as adopted by reference in Colorado Regulation No. 6, Part A, as follows (Colorado Construction Permit 20AD0714):

The requirements below reflect the rule language in 40 CFR Part 60 Subpart Db as of the latest revisions to 40 CFR Part 60 Subpart Db published in the Federal Register on February 27, 2014. However, if revisions to this Subpart are promulgated at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60 Subpart Db.

Standard for nitrogen oxides (§60.44b)

19.5.1 On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO2) in excess of 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. (60.44b(l)(1))

19.5.2 For purposes of 60.44b(i) (Condition 19.5.3), the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction. (60.44b(h))

19.5.3 Except as provided under 60.44b(j), compliance with the emission limits under this section is determined on a 30-day rolling average basis. (60.44b(i))

Compliance and performance test methods and procedures for nitrogen oxides (§60.46b)

19.5.4 Compliance with the NO_X emission standards under §60.44b (Condition 19.5.1) shall be determined through performance testing under 60.46b(e) or (f) (Condition 19.5.5), or under 60.46b(g) and (h), as applicable. (60.46b(c))

19.5.5 To determine compliance with the emission limits for NO_X required under §60.44b (Condition 19.5.1), the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b). (60.46b(e))

19.5.5.1 For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b (Condition 19.5.1). The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. (60.44b(e)(1))

19.5.5.2 Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X

standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) (Condition 19.5.8) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days. (60.44b(e)(4))

Emission monitoring for nitrogen (§60.48b)

19.5.6 Except as provided under 6048b(g), (h), and (i), the owner or operator of an affected facility subject to a NO_X standard under §60.44b (Condition 19.5.1) shall comply with either 60.48b(b)(1) or (b)(2). (60.48b(b))

19.5.6.1 Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system. (60.48b(b)(1))

The CEMS shall meet the CEMS requirements in Condition 59.

19.5.7 The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by 60.48b(b) (Condition 19.5.6 and required under §60.13(h) (Conditions 59.2.3 through 59.2.5) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2) (Condition 59.2.4). (60.48b(d)).

19.5.8 The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall comply with the provisions of 60.48b(b), (c), (d), (e)(2), (e)(3), and (f) (Conditions 19.5.6, 19.5.7 and 59.5) . (60.48(g)(1))

Reporting and Recordkeeping Requirements (§60.49b)

19.5.9 Except as provided in 60.49b(d)(2), the owner or operator of an affected facility shall record and maintain records as specified in 60.49b(d)(1) (see below). (60.49b(d))

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

19.5.10 Except as provided under 60.49b(p), the owner or operator of an affected facility subject to the NO_X standards under §60.44b (Condition 19.5.1) shall maintain records of the information in 60.49b(g)(1) through (10) for each steam generating unit operating day. (60.49b(g))

19.6 Consumption of refinery fuel gas from this boiler shall not exceed 1,138,800 MMBtu/year (Colorado Construction Permit 20AD0714). Refinery fuel gas will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limits shall be monitored by recording the fuel use monthly. Monthly quantities of fuel used shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

19.7 This boiler is subject to the opacity limits set forth in Conditions 35.1, 35.2 and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

19.8 This boiler is subject to 40 CFR Part 63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, as set forth in Condition 63 of this permit.

19.9 This boiler is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit. (Colorado Construction Permit 20AD0714)

19.10 This boiler is subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

19.11 **State-Only Requirement.** This boiler is subject to the requirements in Colorado Regulation No. 23, “Regional Haze Limits”, as follows:

Note that the language below is from Colorado Regulation No. 23, adopted by the Colorado Air Quality Control Commissions (AQCC) on December 17, 2021 (effective January 30, 2022). However, if revisions to Colorado Regulation No. 23 are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Colorado Regulation No. 23.

19.11.1 NO_X emissions shall not exceed 0.06 lb/MMBtu, on a 30-day rolling average (Colorado Regulation No. 23, Section IV.F.3):

19.11.2 At all times after the compliance deadline specified in Regulation Number 23, Sections IV.A.3., IV.B.3., or IV.F.4., the owner/operator of each BART or RP unit must maintain, calibrate, and operate a CEMS in full compliance with the requirements in 40 CFR Part 60, Section 60.13 and 40 CFR Part 60, Appendices A, B, and F to accurately measure, as applicable based on the regional haze limits in Sections IV.A.2, IV.B.2, or IV.F.3, SO2, NOX, and diluents, if diluent is required. The CEMS must be used to determine compliance with the applicable SO2 and NOx regional haze emission limits for each such unit. For particular units, such limits are expressed in units of pounds per hour, tons per year, pounds per ton clinker, or pounds per million Btu. The owner/operator must calculate emissions in the applicable units. In determining compliance with the SO2 and NOx regional haze limits, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions. (Colorado Regulation No. 23, Section V.A.1.b)

The NO_X CEMS shall meet the requirements in Condition 59. Excess emissions shall be reported as required by Condition 59.4.

19.11.2.1 For any hour in which fuel is combusted in the BART or RP unit, the owner/operator must calculate hourly NOx and SO2 emissions in the appropriate units (lbs/hr) or (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values must be used to determine compliance in accordance with the particular limits averaging time, as follows. (Colorado Regulation No. 23, Section V.A.1.b.(i)

a. Before the end of each operating day, the owner/operator must calculate and record the 30-day rolling average emission rate in lb/MMBtu or lb/hr from all valid hourly emission values from the CEMS for the previous 30 operating days. (Colorado Regulation No. 23, Section V.A.1.b.(i)(A))

20. Sulfur Recovery Units (SRU #1 – P101, SRU #2 – P102) with Tail Gas Unit (TGU) and TGU Incinerator – H-25

Emissions from the SRUs are routed through the TGU and vented through the TGU incinerator.

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	20.1	0.48 tons/yr	7.45×10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
	20.2	0.10 gr/dscf @ 12% CO_2		Waste Restriction	Only Gaseous Waste is Combusted
PM_{10}	20.1	0.48 tons/yr	7.45×10^{-3} lb/MMBtu	Recordkeeping and Calculation	Monthly
SO_2	20.1	15.68 lbs/hr 59.7 tons/yr		Continuous Emission Monitor	Continuously
	20.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 20.3	Recordkeeping Calculation	Daily Monthly
	20.4	Startup/Shutdown Provisions		See Condition 20.4	
NO_X	20.1	1.97 tons/yr	0.03 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC		0.35 tons/yr	5.39×10^{-3} lb/MMBtu		
CO		2.63 tons/yr	0.04 lb/MMBtu		
NSPS Requirements	20.5	Subpart J – SRUs[1]: 250 ppmvd SO_2 at 0% excess air, on a 12-hour rolling average		Continuous Emission Monitor	Continuous
		Subpart J - H-25: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[2]		Continuous Monitoring System	Continuous
		General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Sulfur Pit Emissions[1]	20.6	See Condition 20.6		See Condition 20.6	
Fuel Combusted	20.7	131,400,000,000 Btu/yr		Recordkeeping	Monthly
Sour Water Stripper Gas Processing	20.8	See Condition 20.8		See Condition 20.8	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
MACT Standard	20.9	Emission Limit: 250 ppmv (dry basis) SO_2, corrected to 0% O_2, on a 12-hour rolling average Operating limits during startup and shutdown[3]: Maintain the hourly average firebox temperature and O_2 concentration at or above 1,200 ºF and 2%		See 40 CFR Part 60 Subpart UUU (condition 54)	
RACT	20.10	See Condition 20.10		See Condition 20.10	
Opacity	20.11	Not to exceed 20%, except as provided for below		Visual Inspection	Monthly
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes		Method 9	Quarterly
		Not to exceed 20% - (**State-Only**)			
Tail Gas Incidents	20.12	See Condition 20.12		See Condition 20.12	
Continuous Emission Monitoring System Requirements	20.13	See Condition 20.13		See Condition 20.13	
Restrictions on Relaxing Emission Limitations	20.14	See Condition 20.14		Certification	Annually

[1]Note: Emissions from SRU #1, SRU #2 and their associated sulfur pits are routed through the TGU and then to the TGU incinerator. Therefore, emissions from the SRUs and sulfur pits (T2005 and T2000) are measured at the TGU incinerator (H-25) stack.

[2]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

[3]During periods of startup and shutdown, the source may elect to comply with these requirements or the emission and operating limitations or startup and shutdown purge gases can be routed to a flare that meets the requirements in 40 CFR Part 63 §§ 63.670 & 63.671.

20.1 Emissions of air pollutants from the TGU incinerator (H-25) are subject to the following requirements:

20.1.1 Emissions of PM, PM_{10}, CO, VOC and NO_X from the TGU incinerator (H-25) shall not exceed the limits listed in the above table (Colorado Construction Permit 04AD0111). Compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above summary table (PM, PM_{10} and VOC from AP-42, Section 1.4. dated 3/98, Table 1.4-2, NO_X and CO from manufacturer) and the monthly fuel gas consumption (as required by Condition 20.7) in the equation below.

Emissions (Tons/Year) = [EF (lbs/MMBtu) x fuel usage (MMBtu/year)]/2000 lbs/ton

Monthly emissions shall be calculated by the end of the subsequent month and used in rolling twelve month totals to monitor compliance with the annual limitations. Each month new twelve month totals shall be calculated using the previous twelve months data.

20.1.2 Emissions of SO_2 from the TGU incinerator (H-25) shall not exceed 15.68 lbs/hr and 59.7 tons/yr. (Colorado Construction Permit 04AD0111 and Colorado Regulation No. 23, Section IV.F.3 for the annual SO_2 limit) Compliance with the SO_2 limits shall be monitored using the SO_2 continuous emission monitoring system required by Condition 20.13. For every hour that gases are routed to the TGU incinerator (H-25), hourly SO_2 emissions (in lb/hr) shall be calculated using the following procedures:

The TGU stack is equipped with two SO_2 CEMS, one reporting low range (0-495 ppm) and one reporting high range (1 to 4%), so a composite SO_2 concentration is tracked.

- If SO_2 ppm (at stack O_2 and 60 °F) from the low range analyzer is less than 495 ppm, then the low range analyzer shall be used to estimate emissions.
- If SO_2 ppm (at stack O_2 and 60 °F) from the low range analyzer is greater than or equal to 495 ppm, then the high range analyzer must be used.

SO_2 (lb/hr) = SO_2 ppm (at stack O_2 and 60°F) x stack flow (scf/min) x correction factor

Correction factor = 1 ft^3 $SO_2/10^6$ ft^3-ppm exhaust x lbmole SO_2/359.04 ft^3 SO_2 x 491.67 °R/519.67 °R x 12.12 psia/14.7 psia x 64.05 lb SO_2/lbmole SO_2 x 60 min/1 hr = 8.3495 x 10^{-6}

The correction factor changes the molar volume constant (359.04 scf/lbmole) for 1 atm (14.7 psia) and 0 °C (491.67 °R) to 12.12 psia and 60°F C (519.67 °R) per EPA guidance and to convert from minutes to hours (exhaust gas flow rate time span is 1 minute).

Hourly SO_2 emissions (in lbs/hr) shall be be compared to the hourly SO_2 emission limit of 15.68 lbs/hr to assess compliance with the short-term limitation.

Hourly SO_2 emissions shall be summed to get daily SO_2 emissions. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions. Monthly emissions shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

20.2 In areas designated as nonattainment or attainment/maintenance for particulate matter, no owner or operator of an incinerator shall cause or permit emissions of more than 0.10 grain of particulate matter per standard cubic foot (dry flue gas corrected to 12 percent carbon dioxide). (Colorado Construction Permit 04AD0111 and Colorado Regulation No. 1, Section III.B.2.a) In the absence of credible evidence to the contrary, compliance with the PM standard shall be presumed since only gaseous waste is permitted to be combusted in the tail gas incinerator.

20.3 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from the TGU incinerator (H-25) shall be calculated as set forth in Condition 20.1.2 of this permit.

20.4 During the life of the Consent Decree, for the purpose of determining compliance with the SRP [SRP means Sulfur Recovery Plant – SRUs #1 and #2] emission limits, the permittee shall apply the "startup/shutdown" provisions set forth in NSPS Subpart A to the Claus Sulfur Recovery Plant and not to the independent start-up or shutdown of its corresponding control device(s) (e.g. TGU). However, the malfunction exemption set forth in NSPS Subpart A shall apply to both the Claus Sulfur Recovery Plant and its control device(s) (e.g. TGU). (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirements for the SRU. Consent Decree (H-01-4330), Paragraph 175) These provisions apply with respect to the emission limitations in Condition 20.5.

20.5 These sources are subject to NSPS requirements as follows:

20.5.1 The SRUs are subject to the NSPS requirements in 40 CFR Part 60 Subpart J as set forth in Condition 45 of this permit.

20.5.2 The fuel gas used at the tail gas incinerator is subject to the fuel gas requirements of 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit. This limitation applies to the fuel gas combusted in the TGU incinerator and does not apply to the offgas (tail gas) combusted by the incinerator.

20.5.3 These sources are subject to the NSPS general provisions as set forth in Condition 56 of this permit.

20.6 All sulfur pit emissions to the atmosphere shall be either eliminated or included and monitored as part of the SRP's emissions. (Colorado Construction Permit 04AD0111 and Consent Decree (H-01-4430), Paragraph 173) Vents from the #1 SRU sulfur pit and #2 SRU sulfur pit are vented to the TGU incinerator and emissions are monitored via the SO_2 CEMS.

20.7 Consumption of gaseous fuel in the tail gas incinerator (H-25) shall not exceed 131,400,000,000 Btu per year (Colorado Construction Permit 04AD0111). Refinery fuel gas shall be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value analyzed once per week). Compliance with the annual limit shall be monitored as follows:

20.7.1 Daily tail gas flow is monitored using the flow meter. Tail gas streams located downstream of the flow meter shall be calculated using process knowledge. Daily tail gas from the flow meter and calculated streams shall be summed together. Daily total tail gas throughput shall be summed together to get monthly tail gas throughput. Records of daily tail gas calculations, methods and assumptions shall be maintained and made available to the Division upon request. The Btu content of the tail gas shall be assumed to be 27.86 Btu/scf (HHV). Alternatively, if tail gas Btu testing is completed for the #1 and #2 SRU tail gas stream, the most current site-specific value shall be used.

20.7.2 Refinery fuel gas (supplemental fuel) will be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Daily quantities of fuel gas shall be summed to get monthly fuel gas values.

Monthly quantities of tail and fuel gas shall be summed together and used shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

20.8 All gas from the sour water stripper shall be processed through the #2SRU/TGU and/or the #1 SRU/TGU except for emergency startup, shutdown, or malfunction conditions when flaring may be necessary to maintain safe operations. (04AD0111 and as required by supplemental environmental project (SEP) conducted for Compliance Order on Consent, 98-08-07-02, RCRA (3008) VIII-98-03, dated August 7, 1998)

20.9 This source is subject to 40 CFR Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, as set forth in Condition 54 of this permit.

20.10 These sources are subject to Reasonably Available Control Technology (RACT) requirements as follows:

20.10.1 These sources are subject to RACT requirements for SO_2 as a PM_{10} precursor. (Colorado Construction Permit 04AD0111 and Colorado Regulation No. 3, Part B, Section III.D.2.b) RACT has been determined to be operation of the tail gas processing unit such that it meets the short-term (lbs/hr) and annual (tons/yr) emission limitations specified in Condition 20.1.

20.10.2 These sources are subject to RACT requirements for PM_{10}, CO and VOC emissions. (Colorado Construction Permit 04AD0111 and Colorado Regulation No. 3, Part B, Section III.D.2.a) RACT has been determined to be the following:

20.10.2.1 For PM_{10} – use of refinery fuel gas which meets the requirements in Condition 20.5.2 (40 CFR Part 60 Subpart J).

20.10.2.2 For VOC and CO – use of good combustion practices.

20.11 These sources are subject to the opacity limits set forth in Conditions 35.1, 35.2 and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.5.

20.12 Tail Gas Incidents are subject to the following requirements:

20.12.1 Tail Gas Flaring Incidents are subject to the Root Cause Failure Analysis and Corrective Action requirements in paragraphs 183 through 188 of the Consent Decree as set forth in Appendix G of the permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate Consent Decree (H-01-4430) requirements related to tail gas flaring. Consent Decree (H-01-4430), paragraph 178)

20.12.2 Tail Gas Incidents are defined as combustion of Tail Gas that is combusted in a monitored incinerator and the amount of SO2 emissions in excess of the 250 ppm limit (as defined in 40 CFR Part 60 §60.104(2)(i)) on a 24-hr average exceeds 500 pounds. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate Consent Decree (H-01-4430) requirements related to tail gas flaring. Consent Decree (H-01-4430), paragraph 155(s))

20.13 Continuous emissions monitoring systems (CEMS) shall be installed for SO_2, O_2 and air flow. (Colorado Construction Permit 04AD0111) The CEMS shall meet the requirements in Conditions 45.4.4 and 59.

20.14 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section VI.B.4).

Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.20 (TGU Incinerator H-25), as well as Sections II.4 (Tanks T52, T774 and T777), II.10 (Y-3 Cooling Tower), II.13 (Boilers B-6 and B-8), II.21 (Process Heaters H-1716 and H-1717), II.27 (Process Heater H-2101) and II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H_2 Plant Drain Systems). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants.

21. Process Heaters H-1716 (Rated at 57.96 MMBtu/hr) and H-1717 (Rated at 38.64 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	21.1	3.15 tons/year	7.45×10^{-3} lb/MMBtu	Recordkeeping Calculation	Monthly
	21.2	See Conditions 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	21.1	3.15 tons/year	7.45×10^{-3} lb/MMBtu	Recordkeeping Calculation	Monthly
NSPS Subpart Ja	21.3	Fuel gas shall not contain H_2S in excess of: 162 ppmv, on a 3-hour rolling average, and 60 ppmv, on a 365 day rolling average		Continuous Monitoring System	Continuous
		H-1716 Only: NO_X emissions shall not exceed 40 ppmvd, corrected to 0% excess air, on a 30-day rolling average basis		Continuous Monitoring System	Continuous
SO_2	21.1	10.30 tons/year	See Condition 21.1	Recordkeeping Calculation	Monthly
	21.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 21.4	Recordkeeping Calculation	Daily Monthly
NOx	21.5	0.04 lb/MMBtu, on a 3-hr rolling average		See Condition 21.5	
	21.1	12.7 tons/year	0.03 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC		2.28 tons/year	5.39×10^{-3} lb/MMBtu		
CO		16.92 tons/year	0.04 lb/MMBtu		
Fuel Consumption	21.6	846,216,000,000 Btu/year		Recordkeeping	Monthly
MACT	21.7	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDDD (Condition 63)	
RACT – Reg 3	21.8	See Condition 21.8		See Condition 21.8	
NSPS General Provisions	21.9	General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Opacity	21.10	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
Restrictions on Relaxing Emission Limitations	21.11	See Condition 21.11		Certification	Annually
RACT – Reg 7	21.12	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	21.13	Combustion Process Adjustment Requirements		See Condition 73	

21.1 Emissions of air pollutants **from heaters H-1716 and H-1717 combined** shall not exceed the limits listed above (Construction Permit 04AD0110). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions **from each heater** using the emission factors in the above table (PM, PM_{10} and VOC from AP-42, Section 1.4. dated 7/98, Table 1.4-2, converted to lb/MMBtu by dividing by 1020 Btu/scf as noted in footnote a; NO_X and CO from manufacturer) and the monthly fuel consumption (as required by Condition 21.6) in the equation below:

Emissions (Tons/Year) = [EF (lbs/MMBtu) x fuel usage (MMBtu/year)]/2000 (lbs/ton)

For SO_2, daily emissions **from each heater** shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 21.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions **from each heater** shall be calculated by the end of the subsequent month and summed together to get combined monthly emissions from heaters H-1716 and H-1717. Combined monthly emissions from heaters H-1716 and H-1717 shall be used in a twelve-month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

21.2 These sources are subject to the particulate matter emission limits set forth in Condition 36.1.

21.3 These heaters are subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

Compliance with the Subpart Ja fuel gas limits shall be monitored using a continuous H_2S monitoring system as specified in Condition 46.14. Compliance with the NSPS Ja NO_X limit for H-1716 shall be monitored using a NO_X continuous emission monitoring system as specified in Condition 46.18.

21.4 Sulfur dioxide emissions from these sources shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from each heater shall be calculated as set forth in Condition 21.1 of this permit.

21.5 NO_X emissions from each heater shall not exceed 0.04 lb/MMBtu, on a 3-hour rolling average (Colorado Construction Permit 04AD0110, as modified under the provisions on Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections II.A.7 and III.b.7 to include the NO_X emission limits in Consent Decree H-01-4430, paragraph 220(a) required for new or modified heaters associated with projects that used reductions from Consent Decree requirements for netting per paragraphs 219 and 220.) Compliance with the NO_X emission limits shall be monitored as follows:

21.5.1 **For heater H-1716:** Compliance with the NO_X limit shall be monitored using the NO_X continuous emission monitoring system required by Condition 21.3. For every hour in which fuel is combusted in heater, the permittee shall program the data acquisition and handling system (DAHS) to calculate the NO_X concentration in lb/MMBtu, in accordance with the requirements in 40 CFR Part 60 and Condition 59.1.1.3.b of this permit. Compliance with the NO_X emission limits in Condition 21.5 shall be based on a 3-hr rolling average. Before the end of each operating hour, the permittee must calculate and record the 3-hr rolling average emission rate in lb/MMBtu from the previous three operating hours. (An operating hour is any hour in which fuel is combusted for any time in the unit.)

21.5.2 **For heater H-1717:** Compliance with the NO_X limit shall be monitored by conducting a compliance test within 180 days of renewal permit issuance **July 9, 2024**. Frequency of testing thereafter shall be based on the test results: no further testing is required if NO_X emissions are less than or equal to 50% of the NO_X emission limit, every five (5) years if NO_X emissions are greater than 50% but less than or equal to 75% of the NO_X emission limit and every two (2) years if NO_X emissions are greater than 75% of the NO_X emission limit.

If a NO_X compliance test has been conducted within one year of renewal permit issuance **July 9, 2024**, upon written approval from the Division, the permittee may rely on that test to meet the initial test requirement and establish ongoing compliance test frequency. The compliance tests shall be conducted using the appropriate EPA Test Methods.

The compliance test must be conducted in accordance with the most recent version of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/sites/default/files/AP_Compliance-Test-Manual.pdf), including deadlines for preparation and submittal of the protocol for Division review and approval and for submittal of the test report. All compliance testing must be approved by the Division prior to conducting the test.

21.6 Consumption of gaseous fuel **in heaters H-1716 and H-1717 combined** shall not exceed 846,216,000,000 Btu (HHV) per year (Colorado Construction Permit 04AD0110). Refinery fuel gas shall be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value analyzed once per week). Compliance with the annual fuel use limit shall be monitored by recording the quantity of fuel consumed in each heater monthly. Monthly quantities of fuel used for each heater shall be summed together to get combined monthly fuel use from heaters H-1716 and H-1717. The combined monthly fuel use from heaters H-1716 and H-1717 shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month rolling total shall be determined using the previous twelve months data.

21.7 The heaters are subject to the National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63 Subpart DDDDD as set forth in Condition 63 of this permit.

21.8 The heaters are subject to RACT requirements for PM_{10}, VOC, CO and NO_X (VOC and NO_X are ozone precursors). (Colorado Construction Permit 04AD0110 and Colorado Regulation No. 3, Part B, Section III.D.2.a) RACT has been determined to be the following:

21.8.1 For PM_{10} – Use of refinery fuel gas which meets the requirements in Condition 21.3.

21.8.2 For CO and VOC – Use of good combustion practices. In the absence of credible evidence to the contrary, compliance with the VOC and CO RACT requirements shall be presumed provided the requirements in Conditions 21.9 (NSPS General Provisions) and 21.13 (Reg 7 combustion process adjustment requirements) are met.

21.8.3 For NO_X – low NO_X burners.

21.9 The heaters are subject to the general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

21.10 The heaters are subject to the opacity limits set forth in Conditions 35.1, 35.2 and 35.3 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.4.

21.11 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section VI.B.4).

Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.21 (Process Heaters H-1716 and H-1717), as well as Sections II.4 (Tanks T52, T774 and T777), II.10 (Y-3 Cooling Tower), II.13 (Boilers B-6 and B-8), II.20 (TGU Incinerator H-25), II.27 (Process Heater H-2101) and II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H_2 Plant Drain Systems). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants.

21.12 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, these heaters are subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

21.13 These heaters are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on each heater’s actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

22. Fluid Catalytic Cracking Unit (FCCU) Regenerator(P103) and FCCU Catalyst Handling

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM – **State-Only**	22.1	85.4 tons/yr	1 lb/1,000 lb coke burn-off	Recordkeeping Calculation	Annually
				Compliance Tests	See Conditions 22.1.1.2 and 22.1.1.3
				CAM	
PM_{10}	22.1		1 lb/1,000 lb coke burn-off	Recordkeeping Calculation	Annually
SO_2	22.1		CEMS	CEMS	Continuously
	22.2	50 ppmvd at 0% O_2, on a 7-day rolling average 25 ppmvd at 0% O_2, on a 365 day rolling average			
	22.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 22.3	Recordkeeping Calculation	Daily Monthly
NO_X	22.1		CEMS	CEMS	Continuously
	22.4	86.8 ppmvd at 0% O_2, on a 7-day rolling average 58.7 ppmvd at 0% O_2, on a 365-day rolling average			
CO	22.1				
VOC			7.48 lb/Mbbl fresh feed	Recordkeeping Calculation	Annually
FCCU Feed Rate	22.5			Recordkeeping	Daily
Coke Burn-Off	22.6	170,820,000 lb/yr		Recordkeeping	Daily Monthly
Opacity	22.7	Not to exceed 20%, except as provided for below		<u>FCCU regenerator and removal of catalyst buildup in waste heat boiler:</u> COMS	Continuously
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes		<u>Catalyst Loading/ Unloading</u>: Method 9	Quarterly
Hydrotreater Outages - Consent Decree	22.8	See Condition 22.8		See Condition 22.8	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM Reductions – Consent Decree	22.9	1 lb/1,000 lbs coke burned		Performance Test	Annually
				CAM	See Condition 22.9.1.2
CO Reductions – Consent Decree	22.10	500 ppmvd at 0% O_2 on a 1-hr average		CEMS	Continuously
		150 ppmvd at 0% O_2 on a 365-day rolling average			
NSPS	22.11	General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60 Subparts A (Condition 56) and J (Condition 45)	
		PM: 1 1b/1,000 lbs coke burn-off CO: 500 ppmvd Opacity: Not to exceed 30% except for one 6 minute average opacity reading in any 1-hour period			
MACT	22.12	<u>Emission Limits:</u> PM: 1 1b/1,000 lbs coke burn-off Opacity: Not to exceed 30% except for one 6 minute average opacity reading in any 1-hour period CO: 500 ppmvd <u>Operating Limits:</u> Opacity not to exceed 20% on a 3-hour rolling average <u>During startup, shutdown and hot standby[1]:</u> maintain inlet velocity at or above 20 ft/sec (PM/opacity) maintain the O_2 concentration at or above 1 vol % (dry)		See 40 CFR Part 63 Subpart UUU (Condition 54)	
CAM Requirements	22.13	See Condition 22.13		See Condition 22.13	
HCN Emissions	22.14	12.8 tons/yr	0.15 lb/1000 lb coke burn-off	Recordkeeping Calculation Performance Test	Monthly Annually
FCCU Automated Shutdown System Operations & Maintenance Plan	22.15				

22.1 Emissions of air pollutants from the FCCU Regenerator (P103) are subject to the following requirements:

22.1.1 **State-Only Requirement:** Particulate matter (PM) emissions shall not exceed 85.4 tons/yr (Colorado Regulation No. 23, Section IV.F.3). Compliance with the annual emission limit shall be monitored as follows:

22.1.1.1 Emissions from the Suncor FCC Units must be calculated monthly using the quantity of coke burn-off in the following equation. Monthly emissions must be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitations. Each month a new twelve-month total must be calculated using the previous twelve months of data. (Colorado Regulation No. 23, Section V.B.4.e.(ii))

PM Emissions (Tons/Month) = [1 (lb/1,000 lbs coke burn-off) x coke burn-off (lbs/month)]/2000 lbs/ton

22.1.1.2 Compliance tests conducted as required by Condition 22.9.1.1 shall be used to assess compliance with the annual emission limitation in Condition 22.1.1.

Any compliance test conducted to show compliance with a monthly or annual emission limitation must have the results projected up to the monthly or annual averaging time by multiplying the test results by either the allowable number of operating hours for that averaging time or the Throughput Limit(s) (see Condition 22.6) for that averaging time.

The compliance test must be conducted in accordance with the most recent version of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/sites/default/files/AP_Compliance-Test-Manual.pdf), including deadlines for preparation and submittal of the protocol for Division review and approval and for submittal of the test report. All compliance testing must be approved by the Division prior to conducting the test.

22.1.1.3 Complying with the CAM requirements in Condition 22.13.

22.1.2 For APEN reporting and fee purposes, annual emissions of PM_{10}, and VOC shall be calculated using the emission factors listed in the above table (for PM_{10} – NSPS J limit, and VOC – February 2001 performance test conducted on Plant 2 FCCU) and the annual quantities of fresh feed (as required by Condition 22.5) or coke burn-off (as required by Condition 22.6) in the following equations:

VOC Emissions (Tons/Year) = [EF (lbs/Mbbl fresh feed) x feed rate (Mbbl/year)]/2000 (lbs/ton)

PM_{10} Emissions (Tons/Year) = [EF (lbs/1,000 lbs coke burn-off x coke burn-off (lbs/year)]/2000 lbs/ton

22.1.3 For APEN reporting and fee purposes, annual emissions of SO_2 shall be determined using the CEMS required by Condition 22.2.2. For every hour that the FCCU is operating, hourly SO_2 emissions shall be calculated as follows:

SO_2 (lb/hr) = SO_2 ft^3 (dry, zero O_2)/10^6 ft^3 stack flow x stack flow (scfm, dry x 9.97 min-lb SO_2/hr-ft^3 SO_2

Where: stack flow (scfm, dry) = stack flow (scfm, wet) x (100% - x.xx% H_2O)
x.xx% = sample moisture content (following H_2O removal in sample train, sample moisture content verified during required RATA and most recent measurement will be used to calculate emissions, typical value is 8.7%)
stack flow (scfm, wet) = process flow analyzer value for stack exhaust flow, wet
9.97 min-lb SO_2/hr-ft^3 SO_2 = conversion factor = 60 min/hr x lb-mole SO_2/358.4 ft^3 SO_2 (at 68°F) x 64.063 lb SO_2/lb-mole SO_2
SO_2 ft^3 (dry, zero) = SO_2 ft^3 (dry)/10^6 ft^3 stack flow x 20.9%/(20.9% - %O_2 (dry))
SO_2 (dry) = stack gas concentration of SO_2 measured by CEMS, corrected for water vapor per equation above.
20.9% O_2 = atmospheric O_2 concentration
% O_2 (dry) = stack gas concentration of O_2 measured by CEMS, corrected for water vapor

Hourly SO_2 emissions shall be summed to get daily SO_2 emissions. Daily emissions shall be summed to get annual SO_2 emissions.

22.1.4 For APEN reporting and fee purposes, annual emissions of NO_X shall be determined using the CEMS required by Condition 22.4.2 as follows:

For every hour that the FCCU is operating, the permittee shall program the data acquisition and handling system to calculate lb/hr of NO_X emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass NO_X emissions (in lb/hr) shall be calculated using the following equation:

$E_h = K \times C_d \times Q_d \times 60$ min/hr

Where: E_h = mass emissions (lb/hr)
$K = 1.212 \times 10^{-7}$ (lb/ppm-scf)
C_d = NO_X concentration, dry basis, ppm
Q_d = volumetric flow rate, dry basis, scfm

The resulting NO_X lb/hr value is then multiplied by the unit operating time for the FCCU for that hour to produce a NO_X lbs value. Hourly NO_X emissions (lbs) shall be summed and divided by 2000 to determine annual NO_X emissions (in tons).

22.1.5 For APEN reporting and fee purposes, annual emissions of CO shall be determined using the CEMS required by Conditions 22.10.3 and 45.4.2 as follows:

For every hour that the FCCU reactor regenerator (P103) is operating, the permittee shall program the data acquisition and handling system to calculate lb/hr of CO emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass CO emissions (in lb/hr) shall be calculated for each boiler using the following equation:

$E_h = K \times C_d \times Q_d \times 60$ min/hr

Where: E_h = mass emissions (lb/hr)
$K = 7.38 \times 10^{-8}$ (lb/ppm-scf)
C_d = CO concentration, dry basis, ppm
Q_d = volumetric flow rate, dry basis, scfm

The resulting CO lb/hr value is then multiplied by the unit operating time for the FCCU for that hour to produce a CO lbs value. Hourly CO emissions (lbs) shall be summed and divided by 2000 to determine annual CO emissions (in tons).

22.2 SO_2 emissions from the FCCU Regenerator (P103) are subject to the following requirements:

(As provided for in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X per September 12, 2011 modification application to include SO_2 limits and monitoring as required by Consent Decree No. H-01-4430, paragarph 210(a))

22.2.1 SO_2 emissions from the FCCU shall not exceed the following limitations (paragraph 38 and Colorado Regulation No. 23, Section IV.F.3 for the 365-day limit)

22.2.1.1 50 ppmvd at 0% O_2, on a 7-day rolling average, and

22.2.1.2 25 ppmvd at 0% O_2, on a 365-day rolling average.

22.2.2 The permittee shall use a SO_2 and O_2 CEMS to report compliance with the emission limits specified in Condition 22.2.1 (paragraph 43 and Colorado Regulation No. 23, Section V.A.1.e). The SO_2 and O_2 CEMS shall be installed, certified, calibrated, maintained and operated in accordance with the requirements in Condition 59 of this permit. (paragraph 45)

For every hour that the FCCU is operated, the permittee shall calculate hourly average SO_2 ppm concentration (dry basis, at 0% O_2) using the procedures in 40 CFR Part 60 and Condition 59.1.1.3.b. At the end of each operating hour, 7-day and 365-day rolling averages shall be calculated and recorded from all valid hourly SO_2 concentrations for the previous 7 and 365 operating days, except as provided for in Condition 22.8.2.

22.2.3 The permittee shall make CEMS and process data available to the EPA [and the Division] upon demand as soon as practicable. (paragraph 44)

22.3 Sulfur dioxide emissions from the FCCU Regenerator (P103) shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emissions limit, daily SO_2 emissions shall be calculated as set forth in Condition 22.1.3 of this permit.

22.4 NO_X emissions from the FCCU Regenerator (P103) are subject to the following requirements:

(As provided for in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X per September 12, 2011 modification application to include NO_X limits and monitoring as required by Consent Decree No. H-01-4430, paragraph 210(a))

22.4.1 NO_X emissions from the FCCU shall not exceed the following limitations (paragraph 15):

22.4.1.1 86.8 ppmvd at 0% O_2, on a 7-day rolling average, and

22.4.1.2 58.7 ppmvd at 0% O_2, on a 365-day rolling average.

22.4.2 The permittee shall use a NO_X and O_2 CEMS to report compliance with the emission limits specified in Condition 22.4.1 (paragraph 28). The NO_X and O_2 CEMS shall be installed, certified, calibrated, maintained and operated in accordance with the requirements in Condition 59 of this permit. (paragraph 30)

For every hour that the FCCU is operated, the permittee shall calculate hourly average NO_X ppm concentration (dry basis, at 0% O_2) using the procedures in 40 CFR Part 60 and Condition 59.1.1.3.b. At the end of each operating hour, 7-day and 365-day rolling averages shall be calculated and recorded from all valid hourly NO_X concentrations for the previous 7 and 365 operating days, except as provided for in Condition 22.8.1.

22.4.3 The permittee shall make CEMS and process data available to the EPA upon demand as soon as practicable. (paragraph 29)

22.5 Fresh feed to the FCCU shall be tracked and recorded daily and summed monthly. Monthly quantities of fresh feed shall be used to determine annual consumption and to calculate VOC emissions as required by Condition 22.1.

22.6 The quantity of coke burn-off from the FCCU Regenerator (P103) shall not exceed 170,820,000 lb per year. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Sections II.A.4 & 7 and Part C, Sections I.A.7 and III.B.7 and Colorado Regulation No. 8, Part E, Section IV, based on requested throughput identified on the APEN submitted on November 8, 2016, red-lined December 2, 2016) Compliance with the coke burn-off limit shall be monitored by recording the quantity of coke burn-off daily. Daily coke burn-off values shall be summed to get the monthly quantity of coke burn-off. Monthly quantities of coke burn-off shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data. The monthly and annual coke burn-off shall be used to calculate emissions as specified in Conditions 22.1 and 22.14.

22.7 The FCCU Regenerator (P103) and FCCU catalyst handling (loading, unloading and removal of catalyst buildup in waste heat boiler) are subject to the Regulation No. 1 opacity limits set forth in Conditions 35.1and 35.2 of this permit. Compliance with the opacity limits shall be monitored as set for in Conditions 35.6.1 (FCCU regenerator), 35.6.2 (catalyst buildup in waste heat boiler) and 35.6.3 (FCCU catalyst loading and unloading).

22.8 Hydrotreater Outages are subject to the following requirements: (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the requirements in Consent Decree (H-01-4430) related to hydrotreater outages.)

22.8.1 The permittee shall comply with the plan to minimize NOx emissions from the FCCU at all times, including periods of startup shutdown and malfunction. The short-term (7-day rolling) NOx emission limit shall not apply during hydrotreater outages provided that the permittee is maintaining and operating the FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. (paragraph 27)

22.8.2 The permittee shall comply with the plan to minimize SO_2 emissions from the FCCU (including associated air pollution control equipment) during hydrotreater outages as of the Date of Purchase (August 1, 2003). The seven (7) day SO_2 emission limits shall not apply during periods of hydrotreater outages provided that the permittee is maintaining and operating the FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. Following the installation of a wet gas scrubber at the FCCU, this Condition 22.8.2 shall no longer apply to the FCCU. (paragraph 41)

22.8.3 A Hydrotreater Outage shall mean the period of time during which the operation of an FCCU is affected as a result of catalyst change-out operations or shutdowns required by ASME pressure vessel requirements or state boiler codes, or as a result of malfunction, that prevents the hydrotreater from effectively producing the quantity and quality of feed necessary to achieve established FCCU emission performance. (paragraphs 27 and 41)

22.9 Reductions of PM Emissions from the FCCU Regenerator (P103) are subject to the following requirements;

(As provided for in Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7, III.B.7 and V.C.5 to incorporate requirements in Consent Decree (H-01-4430) related to FCCU PM and opacity requirements and monitoring)

22.9.1 The permittee shall comply with a PM emissions limit of 1 pound per 1000 pounds of coke burned as demonstrated by a stack test as described below. (Paragraph 46)

22.9.1.1 PM Monitoring – FCCU. Pursuant to the original Consent Decree, a stack test protocol was proposed and submitted for approval to EPA and the applicable Plaintiff-Intervener no later than 240 days after lodging. This test protocol was submitted for all covered refineries on August 6, 2002. Each company will follow the test methods specified in 40 C.F.R.

§60.106(b)(2) or as in the protocol submitted to EPA, if approved, to measure PM emissions from the FCCUs. Following installation of the control device selected for that particular facility, the Company shall conduct annual stack tests by December 31 of each calendar year at the FCCU and will submit the results of each test in the first report due under Section XIV [semi-annual reports required by Condition 38.5.3] that is at least three (3) months after the test. Company may request to EPA that tests be conducted less frequently than annually upon a showing of at least three (3) annual tests that the PM limits are not being exceeded at a particular facility. (Paragraph 47(a))

22.9.1.2 In addition to the performance test required by Condition 22.9.1.1, the permittee shall comply with the CAM requirements in Condition 22.13.

22.9.2 Opacity Monitoring – FCCU. The permittee shall install, certify, calibrate, maintain, and operate all COMS required by this Condition in accordance with the requirements of Condition 59 of this permit.(Paragraph 47(b))

22.10 Reductions of CO Emissions from the FCCU Regenerator (P103) are subject to the following requirements:

(As provided for in Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7, III.B.7 and V.C.5 to incorporate requirements in Consent Decree (H-01-4430) related to FCCU CO limits and monitoring.)

22.10.1 The permittee shall meet an emission limit of 500 ppmvd CO at 0% O_2 on a 1-hour average basis. (Paragraph 49)

22.10.2 The permittee shall meet an emission limit of 150 ppmvd CO at 0% O_2 on a 365-day rolling average basis.(Paragraph 50)

22.10.3 The permittee shall use a CO CEMS to monitor performance of the FCCU and to report compliance with the emission limitations in Conditions 22.10.1 and 22.10.2. (Paragraph 51) The CO CEMS shall be installed, calibrated, maintained and operated in accordance with the requirements in Condition 59 of this permit. (paragraph 53)

22.10.4 The permittee shall make CEMS and process data available to EPA [and the Division] upon demand as soon as practicable.(Paragraph 52)

22.11 The FCCU Regenerator (P103) is subject to the requirements of NSPS Subparts A and J as set forth in Conditions 45 (Subpart J) and 56 (Subpart A) of this permit. (As provided for in Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A. and, III.B.7 to include Consent Decree (H-01-4430) requirement for the FCCU to meet NSPS A and J requirements. Consent Decree (H-01-4430), Paragraph 54) Compliance with the NSPS Subpart J requirements shall be monitored as follows:

22.11.1 Compliance with the opacity and SO_2 emission limits shall be monitored as required by the provisions in Condition 45 (NSPS J requirements).

22.11.2 In the absence of credible evidence to the contrary compliance with the NSPS J PM emission limit shall be presumed provided the monitoring in Condition 22.9.1 indicates compliance with the PM emission limit in Condition 22.9.1

22.12 The FCCU Regenerator (P103) is subject to 40 CFR Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, as set forth in Condition 54 of this permit.

22.13 The FCCU Regenerator (P103) is subject to the compliance assurance monitoring (CAM) requirements with respect to the particulate matter limitations identified in Conditions 22.1.1, 22.9.1 and 22.11 Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plan in Appendix H.

22.14 Hydrogen Cyanide (HCN) emissions from the FCCU Regenerator (P103) shall not exceed 12.8 tons per year. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Sections II.A.4 & 7 and Part C, Sections I.A.7 and III.B.7 and Colorado Regulation No. 8, Part E, Section IV, based on requested throughput identified on the APEN submitted on November 8, 2016, red-lined December 2, 2016.) Compliance with the HCN emission limits shall be monitored as follows:

22.14.1 Compliance with the annual emissions limits shall be monitored by calculating emissions monthly using the emission factor in the above summary table (from September 2, 2015 performance test) and the monthly quantity of coke burn-off (as required by Condition 22.6) in the equation below:

HCN (tons/mo) = [EF (lb/1000 lb coke burn-off) x monthly coke burn-off (lb/month)]/2000 lb/ton

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

22.14.2 A performance test shall be conducted annually to monitor compliance with the annual HCN emission limitation in Condition 22.14. Annual performance tests shall be conducted no sooner than 11 months and no later than 13 months from completion of the previous test, unless approved by the Division in writing.

Performance tests shall be conducted in accordance with the appropriate EPA Test Methods, using an HCN continuous emission monitoring system. The duration of the performance test shall be 30 days. All valid HCN concentration (ppm) data points shall, at the end of each clock hour be summed to determine the hourly average HCN concentration. Each hourly HCN concentration shall be converted to the appropriate

HCN emission rate(s). All valid HCN emission rate(s) over the 30-day test period shall be averaged together to determine the average HCN emission rate(s).

Any compliance test conducted to show compliance with a monthly or annual emission limitation must have the results projected up to the monthly or annual averaging time by multiplying the test results by either the allowable number of operating hours for that averaging time or the Throughput Limit(s) (see Condition 22.6) for that averaging time.

The compliance test must be conducted in accordance with the most recent version of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/sites/default/files/AP_Compliance-Test-Manual.pdf), including deadlines for preparation and submittal of the protocol for Division review and approval and for submittal of the test report. All compliance testing must be approved by the Division prior to conducting the test.

22.15 FCCU Automated Shutdown System Operations & Maintenance Plan

Note that the regulatory basis for these requirements comes from the General Duy obligation from 40 CFR Part 63, Subpart UUU, §63.1570(c).

22.15.1 Within 12 months of issuance of this Operating Permit, Suncor must develop and implement an Operation and Maintenance (O&M) plan for the automated shutdown system installed on the FCCU. The O&M plan must include relevant data or other reasonable technical justification for chosen parameters, which may include but are not limited to the preventative maintenance recommended by equipment vendors and/or manufacturers for the system's automated valves and hydraulic systems.

22.15.2 Instruments and electronics within the system shall be tested on a prescribed frequency, as feasible, while in operation via actions which may include, but are not limited to electrical continuity checks, visual checks for corrosion or fouling, instrument air filter and liquid knockout systems checks, and transmitter electronic output testing.

22.15.3 The O&M plan must include an assessment for periodlically evaluating the functionality of the automated shutdown system programming.

22.15.4 The design of the automated shutdown system shall be evaluated as part of the Management of Change (MOC) process (or equivalent) for design and equipment modifications made in the FCCU to ensure that the system will operate as intended to minimize emissions during unit shutdown.

22.15.5 The O&M plan shall be updated as soon as practicable as needed to incorporate learnings from incident investigations and events that trigger automated shutdowns.

22.15.6 Records must be maintained on site for Division inspection upon request. The records must demonstrate ongoing compliance with the requirements of Condition 22.15.

These records may include, but may not be limited to documentation of the automated shutdown system O&M plan, preventative maintenance recommendations and schedules from FCCU system vendors and/or manufacturers, testing protocols, performed tests and checks, changes made to the O&M plan as a result of equipment changes or incidents. The Division may request that Suncor maintain additional records to demonstrate compliance with this condition if the Division determines that the records submitted by Suncor are insufficient. Deviations from the requirements of Condition 22.15 shall be reported in the semi-annual report to the Division.

23. Plant 1 Wastewater Treatment System – F201

AIRS pt 095 – Tank T4501 (Part of the Slop Oil System)

AIRS pt 146 – Controlled Sources: API Separators (T4514, T4515), DGF System (T4502, T4503, T4504, T4507, T4508), API Lift Station, T60 Lift Station, Slop Oil System (T4516, T4517, T4518), API Headworks, Centrifuge and Associated Control Devices

AIRS pt 149 – Uncontrolled Sources and Sumps: Uncontrolled sources include Equalization Tank (T60), Sludge Thickener Tank (T29), Aeration Tanks (T26, T4511), Clarifiers (T28, T4512), Lagoons 1 thru 4 and Train A Improvement Project Equipment (Aeration Basins 1 and 2, UF and MBR Splitter Boxes and Membrane Tanks 2 through 7). Sumps include Lab, Spider, T58, T70, T75, T80, T775, T777 Sumps and Associated Control Devices

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	23.1	Uncontrolled Sources and Sumps: 5.27 tons/year	See Condition 23.1.1	Recordkeeping Calculation	Monthly
		T4501: 4.64 tons/year	TANKS		
		Controlled Sources: 15.7 tons/year	See Condition 23.1.3		
NO_X	23.1	Controlled Sources: 1.8 tons/year	0.4 lbs/hr	Recordkeeping Calculation	Monthly
CO		Controlled Sources: 14.3 tons/year	3.27 lbs/hr		
SO_2		Controlled Sources: 6.6 tons/year	1.49 lbs/hr	Recordkeeping Calculation	Daily Monthly
	23.14	0.3 lb SO_2/bbl/day of oil processed	See Condition 23.14		
Wastewater/Oil Separators - RACT	23.2	Wastewater/Oil Separators		Inspection	Quarterly
Tanks - RACT	23.3	See Condition 23.3		See Condition 23.3	
MACT	23.4	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
BWON	23.5	See 40 CFR Part 61 Subpart FF (Condition 65)		See 40 CFR Part 61 Subpart FF (Condition 65)	
Throughput – Tank T-4501	23.6	1,567,000 barrels per year of slop oil 15,017,143 barrels per year of sour water and/or wastewater with a floating layer of diesel		Recordkeeping	Monthly
Tanks - NSPS	23.7	General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60, Subparts A (Condition 56) and Kb (Condition 48)	
		Specific Requirements – Subpart Kb			

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
BWON Program Enhancements – Consent Decree Requirements	23.8	See Appendix G		See Appendix G	
Carbon Canister Breakthrough	23.9	Breakthrough Defined as 5 ppm Benzene		See Condition 23.9	
API Headworks	23.10	Replacement of Covers		Inspections	Quarterly (visual) Monthly (NDE – for 24 months)
RTO Requirements	23.11	Closed Vent System and Control Device Shall Meet the Requirements in 40 CFR Part 61 Subpart FF §61.349		Performance Test	Within 90 Days of Startup
		Opacity not to exceed 20%		See Condition 23.11.5	
		Maintain RTO temperature at or above 1578 °F		See Condition 23.11.6	
Hours of Operation	23.12			Recordkeeping	Daily Monthly
CAM Requirements	23.13	See Condition 23.13		See Condition 23.13	

23.1 Air pollutant emissions from these sources are subject to the following requirements:

23.1.1 For the Uncontrolled Sources and Sumps: VOC emissions from the uncontrolled sources and sumps shall not exceed the limit listed in the above summary table. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 based on the emissions requested on the APEN submitted November 23, 2015 and red-lined December 1, 2015).

The uncontrolled sources include the following: equalization tank (T60), sludge thickener tank (T29), sumps and their associated control devices, aeration tanks (T26-T4511), Clarifiers (T28, T4512), lagoons 1 thru 4 and Train A Improvement Project Equipment (aeration basins 1 and 2, UF and MBR splitter boxes and membrane tanks 2 through 7). Sumps include lab, spider, T58, T70, T75, T80, T775 and T777 sumps and associated control devices.

Compliance with the annual VOC limitation shall be monitored by calculating emissions monthly using hours of operation for the Plant 1 WWTS (as required by Condition 23.12) and the emission factors in the table below in the following equation:

Tons/mo = [EF (lbs/hr) x Plant 1 WWTS hours of operation (hrs/mo)]/2000 lbs/ton

Source	Emission Factor (EF)	Emission Factor Source
All sumps, except spider sump	2.27×10^{-2} lb/hr	AP-42, Section 5.1 (dated 4/2015), Table 5.1-3, oil/water separators, controlled emission factor (0.2 lb/Mgal) maximum hourly flow rates from the BWON TAB reports from 2011 - 2013.[1] Calculated control efficiency from AP-42, Table 5.1-3 is 96% (uncontrolled emission factor is 5 lb/Mgal).
Other Equipment	1.18 lb/hr	Based on ToxChem Model Results submitted on November 23, 2015. Note that spider sump includes 98% control for carbon canisters.

[1]The hourly flow rates (in Mgal/hr) used to get the lb/hr emission factor are as follows: LAB (1.10), T58 (1.44×10^{-1}), T70 (5.89×10^{-2}), T75 (5.89×10^{-2}), T80 (5.84×10^{-2}), T775 (4.09×10^{-1}) and T777 (6.01×10^{-3})

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

In addition, a review of the ToxChem model shall be conducted annually to determine if updates to the model are necessary. The review shall address the addition and/or removal of components and changes in flows and/or concentration levels. Changes to the previous version of the model shall be documented, maintained and made available to the Division upon request.

23.1.2 For T4501: VOC emissions shall not exceed the limit listed in the above summary table. (Colorado Construction Permit 03AD0153, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X based on the emissions requested on the APEN submitted March 5, 2020, red-lined March 19, 2020). Compliance with the annual limits shall be monitored by calculating monthly emissions from the tank using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 23.6). Emissions shall be based on the average (or numerically greater) RVP of the materials stored over the monthly period. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

23.1.3 For the Controlled Sources: NO_X, CO, VOC and SO_2 emissions shall not exceed the limits listed in the above summary table. (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 III.B.7 based on the emissions requested on the APEN submitted April 8, 2015 and red-lined May 14, 2015)

The RTO or carbon canisters control emissions from the API headworks, API lift Station, T60 lift station and centrifuge. Other sources are controlled by carbon canisters but can be routed to the RTO in the future and those sources include the following: API separators (T4514, T4515), DGF system (T4502, T4503, T4504, T4507 and T4508), and the slop oil system (T4516, T4517, T4518).

Except for SO_2 emissions, compliance with the annual emission limitations shall be monitored by calculating emissions monthly using hours of operation for the RTO and WWTS (as required by Condition 23.12) and the emission factors in the table below in the following equations. Monthy emissions shall be calculated by the end of the subsequent month.

Pollutant	Emission Factor (EF)	Emission Factor Source
NO_X	0.4 lbs/hr	Based on manufacturer's guarantee of 0.1 lb/MMBtu, converted to lbs/hr based on design rate of 4 MMBtu/hr
CO	3.27 lbs/hr	Based on manufacturer's guarantee of 50 ppmv and inlet flow rate of 15,000 scfm (RTO design rate)
SO_2	1.49 lbs/hr	Based on an inlet H_2S concentration of 10 ppm (engineering estimate) and inlet flow rate of 15,000 scfm (RTO design rate)
VOC – RTO	2.57 lbs/hr	Based on an inlet flow rate of 15,000 scfm (RTO design rate), VOC concentration of 2,750 ppm (engineering estimate) and an assumed control efficiency of 99%. VOC MW assumed to be 40.
VOC – Centrifuge, carbon canisters	0.06 lbs/hr	Inlet VOC concentration of 100,000 ppmvd (high short-term value during 10/12 performance test) inlet flow rate of 5 scfm (engineering estimate) and an assumed control efficiency of 98%. VOC MW assumed to be 40.
VOC – API headworks, carbon canisters	0.93 lbs/hr	Inlet VOC concentration of 150,000 ppmvd (engineering estimate), inlet flow rate of 50 scfm (engineering estimate) and an assumed control efficiency of 98%. VOC MW assumed to be 40.
VOC – others, carbon canisters	2.49×10^{-2} lbs/hr	Based on ToxChem Model Results submitted on September 3, 2015. Control efficiency of 98% assumed.

<u>NO_X and CO Emissions:</u>

Tons/mo = [EF (lbs/hr) x hours of operation (hrs/mo)]/2000 lbs/ton

<u>VOC Emissions:</u>

VOC emissions = $VOC_{RTO} + VOC_{cc\text{-}RTO} + VOC_{cc} + VOC_{cc\text{-}cent}$

VOC_{RTO} is VOC emissions from the RTO.

VOC_{RTO} = [EF_{RTO} (lbs/hr) x hours RTO operating (hrs/mo)]/2000 lbs/ton

$VOC_{cc\text{-}RTO}$ is VOC emissions from sources normally controlled by the RTO but RTO is not operating and carbon canisters are used as the control.

$VOC_{cc\text{-}RTO}$ = [EF_{cc} (lbs/hr) x hours RTO NOT operating (hrs/mo)]/2000 lbs/ton

VOC_{cc} is VOC emissions from sources not currently controlled by the RTO. Sources are controlled by carbon canisters.

VOC_{cc} = [EF_{cc} (lbs/hr) x hours of operation (hrs/mo)]/2000 lbs/ton

$VOC_{cc\text{-}cent}$ is VOC emissions from the centrifuge when it is not operating and emissions are routed to carbon canisters.

$VOC_{CC\text{-}cent}$ (tons/mo) = [EF_{cc} (lbs/hr) x hours centrifuge NOT operating (hrs/mo)]/2000 lbs/ton

For SO_2, daily emissions shall be estimated using the emission factor in the above table in the following equation:

SO_2 (lbs/day) = [EF (lb/hr) x hours of operation (hrs/day)]

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions shall be used in twelve month rolling totals to monitor compliance with the annual emission limitations. Each month new twelve month totals shall be calculated using the previous twelve months data.

23.2 T4514 and T4515 are subject to Colorado Regulation No. 24, Part B, Section VI.A.2 as set forth in Condition 43.1 of this permit.

23.3 The tanks (T60, T4501, T4502, T4503, T4504, T4507, T4508, T4516, T4517 and T4518) are subject to RACT requirements in Colorado Regulation No. 24, as follows:

23.3.1 All tanks are subject to the requirements in Part B, Section I.A as set forth in Condition 39.1 of this permit.

23.3.2 Tanks T4504, T4516, T4517 and T4518 are subject to the requirements in Part B, Section IV.B.2.a as set forth in Condition41.2.1.

23.3.3 Tanks T60, T4501, T4504, T4516, T4517 and T4518 are subject to the requirements in Part B, Section IV.B.2.b as set forth in Condition 41.2.2.

23.3.4 Tank T60 and T4501 are subject to the requirements in Part B, Section IV.B.2.c as set forth in Condition 41.2.3 of this permit.

23.3.5 Tanks T4502, T4503, T4507 and T4508 are subject to the requirements in Part B, Section IV.B.3 as set forth in Condition 41.6 of this permit.

23.4 The wastewater treatment system is subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 53 of this permit.

23.5 The wastewater treatment system is subject to the requirements of 40 CFR Part 61, Subpart FF, as set forth in Condition 65 of this permit.

23.6 Throughput through tank T4501 shall not exceed the following limitations:

23.6.1 Slop oil shall not exceed 1,567,000 barrels per year. (Colorado Construction Permit 03AD0153, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X based on the throughputs requested on the APEN submitted March 5, 2020, red-lined March 19, 2020)

23.6.2 Sour water and/or wastewater with a floating layer of diesel shall not exceed 15,017,143 barrels per year. (Colorado Construction Permit 03AD0153, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X based on the throughputs requested on the APEN submitted March 5, 2020 and red-lined March 19, 2020)

Compliance with the annual throughput limits shall be monitored by recording the throughput monthly. Monthly quantity of throughput will be used in twelve month rolling totals to monitor compliance with the annual limitations. Each month new twelve month totals shall be calculated using the previous twelve months data. Records of the vapor pressures of stored materials shall be maintained and made available to the Division upon request.

23.7 Tanks T60, T4504, T4514, T4515, T4516, T4517 and T4518 are subject to NSPS requirements as follows:

23.7.1 These tanks are subject to the NSPS general conditions in 40 CFR Part 60 Subpart A as set forth in Condition 56.

23.7.2 These tanks are subject to the specific NSPS requirements for volatile organic liquid (including petroleum liquids) storage vessels in 40 CFR Part 60, Subpart Kb as set forth in Condition 48 of this permit.

23.8 The wastewater treatment system is subject to the BWON Program Enhancements in the Consent Decree (H-01-4430) as set forth in Appendix G of this permit. The BWON Program Enhancement monitoring requirements, as set forth in Appendix G of this permit, include the following:

23.8.1 The permittee shall conduct monthly visual inspections of all water traps used for BWON control within the refinery's individual drain systems. (Paragraph 117(a))

23.8.2 The permittee shall identify and mark all area drains that are segregated storm drains. (Paragraph 117(b)

23.8.3 The permittee shall conduct monitoring of the controlled oil-water separators (T4514 and T4515) on a quarterly basis in accordance with the "no detectable emissions" provisions in 40 CFR §61.347. (Paragraph 117(d))

23.9 Except as provided for in Condition 23.9.1, the permittee shall monitor for breakthrough between the primary and secondary carbon canisters at times there is actual flow to the carbon canister in accordance with the frequency specified in 40 CFR Part 61 Subpart FF §61.354(d). (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate Consent Decree (H-01-4430) requirements related to carbon canisters. Consent Decree (H-01-4430), Paragraph 91)

23.9.1 When vapors from the API headworks are routed to carbon canisters, breakthrough shall be monitored as required by the CAM plan in Appendix M and the CAM requirements in Condition 60 (as required by Condition 23.13).

23.9.2 Breakthrough from carbon canisters shall be defined as any reading equal to or greater than 5 ppm benzene.

23.10 Suncor shall monitor the existing enclosure and seals of the API Headworks as required by Subpart FF §61.346(b)(4) on a quarterly basis. Additionally, by no later than June 30, 2012, Suncor shall start monitoring the API Headworks for "no detectable emissions" on a monthly basis for a period of no less than 24 months, using the procedures set forth in Subpart FF §61.355(h). If any broken seal, gap, crack, leak, or other problem is identified from the quarterly visual inspection (Subpart FF §61.346(b)(4)) or the monthly no detectable emissions inspection shows a reading greater than 500 ppm (Subpart FF §61.355(h)), Suncor will make first efforts at repair as soon as practicable, but not later than 15 calendar days after identification, as specified in Subpart FF §61.346(b)(5). Suncor shall maintain records of all required monitoring and make records available upon request. (Compliance Order on Consent, No. 2011-049, dated 3/28/12, paragraph 13, revised to remove the language regarding actions that Suncor has completed. Note that this permit includes a schedule to install a control device so language related to control device installation was removed.)

23.11 Suncor shall operate a regenerative thermal oxidizer (RTO) in accordance with the following requirements:

23.11.1 The RTO shall be used to control emissions as follows:

23.11.1.1 Beginning no later than December 31, 2013, emissions from the API Headworks shall be routed through a closed vent system to the RTO or carbon canisters (Compliance Order on Consent, No. 2011-049, dated 3/28/12, paragraph 13).

23.11.1.2 The closed vent system, RTO and carbon canisters shall meet the requirements in 40 CFR Part 61 Subpart FF §61.349 (40 CFR Part 61 Subpart FF requirements are in Condition 65 of this permit).

23.11.1.3 Other sources within the Plant 1 WWTS that are identified as controlled sources (see description in Condition 23.1.3) may be routed to the RTO in the future, provided that performance tests are conducted in accordance with the requirements in Condition 23.11.4.

23.11.2 When the RTO is NOT operating the following requirements apply:

23.11.2.1 Emissions that are otherwise controlled by the RTO, including the centrifuge, shall be routed through a closed vent system to two carbon canisters in series. The carbon canisters are subject to the breakthrough requirements in Condition 23.9. The closed vent system and carbon canisters shall meet the requirements in 40 CFR Part 61 Subpart FF §61.349 (40 CFR Part 60 Subpart FF requirements are in Condition 65 of this permit).

23.11.3 The following requirements apply to the centrifuge:

23.11.3.1 When the centrifuge is in operation, the vapors shall be routed to the RTO which shall meet the requirements of Condition 23.11 of this permit.

23.11.3.2 When the centrifuge is not in operation, the vapors shall be routed through a closed vent system to two carbon canisters in series. The carbon canisters are subject to the breakthrough requirements in Condition 23.9. The closed vent system and carbon canisters shall meet the requirements in 40 CFR Part 61 Subpart FF §61.349 (40 CFR Part 60 Subpart FF requirements are in Condition 65 of this permit).

23.11.4 Compliance tests shall be conducted within ninety (90) days of of routing any additional stream (or streams) to the RTO to assess compliance with the VOC, NO_X, CO and SO_2 emission limitations in Condition 23.1.3. The permittee may request that performance testing for the NO_X, CO and SO_2 emission limits be waived for subsequent performance tests if Division approval, in writing, is granted, stating that testing for NO_X, CO and SO_2 is not required for subsequent tests.

Compliance tests shall be conducted in accordance with the requirements and procedures set forth the appropriate EPA Test Methods as set forth in 40 CFR Part 60, Appendix A and the procedures in 40 CFR Part 61 Subpart FF §61.355(i) (to assess compliance with organic emissions reduction requirement in §61.349(a)(2)(i)(A), 61.349(a)(2)(i)(B), or §61.349(a)(2)(i)(C)), unless otherwise approved by the Division in writing.

The compliance test must be conducted in accordance with the most recent version of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/sites/default/files/AP_Compliance-Test-Manual.pdf), including deadlines for preparation and submittal of the protocol for Division review and approval and for submittal of the test report. All compliance testing must be approved by the Division prior to conducting the test.

During each compliance test required by this Condition 23.11.4, the compliance assurance monitoring (CAM) indicator minimum value (combustion zone temperature) shall be revised.

The permittee shall submit the proposed CAM indicator (combustion zone temperature) minimum values determined from any subsequent compliance test for Division approval and begin monitoring under the new value within 45 calendar days of the test. The proposed CAM indicator (combustion zone temperature) minimum value submittal shall include the justification and supporting data for the proposed

CAM indicator. In addition, the permittee shall submit with the proposed CAM indicator a minor modification application to revise the permit to incorporate the proposed minimum for the CAM indicator (combustion zone temperature) into Conditions 23.11.6 and 60 and Appendix M of this permit.

23.11.5 The RTO is subject to the opacity limits set forth in Condition 35.1. In the absence of credible evidence to the contrary compliance with the opacity limitation is presumed provided that only vapors from those portions of the Plant 1 WWTS identified in Condition 23.1.3 and natural gas (as assist gas) are combusted in the RTO. Records shall be maintained to verify that only vapors from those portions of the Plant 1 WWTS identified in Condition 23.1.3 and natural gas have been combusted in the thermal oxidizer.

23.11.6 For purposes of assuring compliance with the annual VOC emission limitation in Condition 23.1.3, the RTO shall be operated such that the temperature in the combustion chamber is not less than 1573 °F. The combustion chamber temperature shall be monitored in accordance with the CAM plan in Appendix M and the CAM requirements in Condition 60 (as required by Condition 23.13).

23.12 Hours of operation for the centrifuge, RTO and Plant 1 WWTS shall be monitored and recorded as follows:

23.12.1 For the RTO daily. Daily hours of operation shall be summed to determine monthly hours of operation for the RTO.

23.12.2 Monthly for the centrifuge and the Plant 1 WWTS.

The permittee shall maintain separate monthly totals of the number of hours the centrifuge and RTO are operated and the number of hours the centrifuge and RTO do not operate. Daily hours of operation for the RTO shall be used to calculate daily SO_2 emissions as specified in Condition 23.1.3. Monthly totals shall be used to calculate emissions as specified in Conditions 23.1.1 and 23.1.3.

23.13 The Plant 1 WWTS RTO and the API headworks, when controlled by carbon canisters, are subject to the compliance assurance monitoring (CAM) requirements with respect to the VOC emission limitation identified in Condition 23.1.3, Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plan in Appendix M.

23.14 Sulfur dioxide emissions from the Plant 1 WWTS RTO shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emissions limit, daily SO_2 emissions shall be calculated as set forth in Condition 23.1.3 of this permit.

24. Rail Loading Rack and Enclosed Vapor Combustion Unit (VCU) – R101

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	24.1		See Condition 24.1.3.1	Recordkeeping Calculation	Monthly
PM_{10}					
SO_2			See Condition 24.1.3.2		Daily, Monthly
	24.2	NSPS Subpart Ja Requirement: Fuel gas shall not contain H_2S in excess of: 162 ppmv, on a 3-hour rolling average, and 60 ppmv, on a 365-day rolling average		See Condition 24.2	
	24.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 24.3	Recordkeeping Calculation	Daily, Monthly
NOx	24.1	5.53 tons/year	0.146 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC		12.5 tons/year	See Condition 24.1		
RACT	24.4	See Condition 24.4		See Condition 24.4	
MACT	24.5	Total organic compound emissions not to exceed 10 mg/l of gasoline loaded.		See 40 CFR Part 63 Subpart CC (Condition 53)	
		Maintain combustion zone temperature at or above 1,299 ºF, on a 6-hour rolling average.			
CO	24.1	15.1 tons/year	0.40 lb/MMBtu	Recordkeeping Calculation	Monthly
Loading/Unloading Throughput	24.6	3,640,000 bbl gasoline/year 546,000 bbl jet fuel/year 1,500,000 bbl distillates/year 340,000 bbl ethanol/year		Recordkeeping	Daily Monthly
Opacity	24.7	Not to exceed 20%, except as provided for below		Visual Inspection	Daily
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
Combustion Zone Temperature	24.8	Maintain combustion zone temperature at or above 1,299 ºF, on a 6-hour rolling average		Thermocouple	Continuously
NSPS General Provisions	24.9	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Pilot and Assist Gas Consumption	24.10	Natural Gas: 48,018 MMBtu/year Propane: 10,194 MMBtu/year		Flow Meter	Daily, Monthly

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Number of Ethanol Rail Cars Unloaded	24.11			Recordkeeping	Monthly
Compliance Test	24.12	Compliance testing for MACT limit (10 mg/l of gasoline loaded), 98% control efficiency and combustion zone temperature		EPA Test Methods	Every Five (5) Years
CAM Requirements	24.13	See Condition 24.13		See Condition 24.13	

24.1 Emissions of air pollutants from the **rail loading rack and enclosed VCU** are subject to the following requirements:

24.1.1 VOC emissions from the **rail loading rack enclosed VCU** shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 88AD012, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase emissions as indicated on the APEN received on June 4, 2019, red-lined on August 28, 2019) Compliance with the annual limits shall be monitored as follows:

24.1.1.1 Monthly VOC emissions from **loading gasoline** shall be calculated using the monthly quantity of gasoline loaded (as required by Condition 24.6) in the below equations:

VOC (tons/mo) = [10 mg/l loaded x monthly quantity loaded (gal/mo) x 3.7854 l/gal x 1 g/1000 mg x 1 lb/453.6 g]/2000 lb/ton

Where: 10 mg/l loaded is the MACT CC emission limit for gasoline loading (40 CFR Part 63 Subpart R § 63.422(b) limit which is required by 40 CFR Part 63 Subpart CC §63.650(a))

24.1.1.2 Monthly VOC emissions **from jet naptha and distillate loading** shall be calculated using the monthly quantity of distillate and jet fuel loaded (as required by Condition 24.6) in the following equation:

VOC (tons/mo) = [LL (lb/10^3 gal) x monthly materials loaded (10^3 gal/mo) x (1 - (control efficiency/100))]/2000 lb/ton

L_L = 12.46 x SPM/T

Where: LL = loading loss (lb/10^3 gal), from AP-42, Section 5.2 (dated 6/08), eqn 1
S = saturation factor (per Table 5.2-1 of AP-42)
P = true vapor pressure of liquid loaded, psia
M = molecular weight of vapors (lb/lbmole)
T = temperature of bulk liquid loaded (º R)

A control efficiency of 98% may be used in the above equation for the vapor combustor provided it meets the requirements in Condition 24.8.

Monthly emissions shall be calculated using the monthly average vapor pressure and temperature of the liquids loaded for the monthly period and constant vapor molecular weights of 130 lb/lbmole for distillate and 80 lb/lbmole for jet fuel.

24.1.1.3 Monthly VOC emissions from the **ethanol deaerators** shall be calculated monthly using the monthly number of ethanol rail cars unloaded (as required by Condition 24.11) in the following equation:

VOC (ton/mo) = [number of ethanol rail cars unloaded x 981 (scf/rail car) x 0.0605 x 0.121 (lb ethanol/scf) x (1 - (control efficiency/100))]/2000 lb/ton

Where: 981 scf/rail car = volume of vapor generated by ethanol deaerator, calculated by dividing mass of N_2 entrained in ethanol liquid (75.56 lb/rail car) divided by the vapor density (0.077 lb/scf), both of which were determined by HYSYS runs.
0.0605 = volume fraction of ethanol in vapor, obtained from HYSYS runs
0.121 lb ethanol/scf = vapor density of ethanol

A control efficiency of 98% may be used in the above equation for the vapor combustor provided it meets the requirements in Condition 24.8.

24.1.1.4 Monthly VOC emissions from **depressurizing ethanol rail cars** shall be calculated monthly using the appropriate emission factor for the month and the number of ethanol rail cars unloaded (as required by Condition) in the equation below:

Quarterly Period	VOC Emission Factor (EF) lb/ rail car
January – March	17.8
April - June	30.6
July - September	41.2
October - December	21.7

VOC (ton/mo) = [EF (lb/rail car) x number of rail cars loaded (rail cars/mo) x (1 - (control efficiency/100))]/2000 lb/ton

A control efficiency of 98% may be used in the above equation for the vapor combustor provided it meets the requirements in Condition 24.8.

24.1.1.5 Monthly VOC emissions **from pilot and assist gas** shall be calculated using the monthly quantity of pilot and assist gas combusted (as required by Condition 24.10) in the following equations:

VOC (ton/mo) = VOC from natural gas + VOC from propane

<u>Natural gas combustion</u>

VOC (tons/mo) = [EF (lb/MMBtu) x monthly pilot/assist gas (MMBtu/mo)]/2000 lb/ton

Where: EF = 0.0395 lb/MMBtu (from Xcel gas composition data, Denver area high pressure line, December 2017, 98% control efficiency assumed)

<u>Propane combustion</u>

VOC (ton/mo) = [monthly pilot/assist gas (MMBtu/mo)/21,580 Btu/lb x 10^6 Btu/MMBtu x (1 - (control efficiency/100))]/2000 lb/ton

Where: 21,580 Btu/lb = [91.5 MMBtu/10^3 gal x 10^6 Btu/MMBtu]/4.24 Btu/gal

91.5 MMBtu/10^3 gal (propane heat content) from AP-42, Section 1.5 (dated 7/08), Table 1.5-1, footnote a.
4.24 lb/gal (propane density) from AP-42, Appendix A.

A control efficiency of 98% may be used in the above equation for the vapor combustor provided it meets the requirements in Condition 24.8

Monthly VOC emissions shall be calculated by the end of the subsequent month. Monthly VOC emissions calculated in accordance with Conditions 24.1.1.1 through 24.1.1.5 shall be summed together and used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

24.1.2 NO_X and CO emissions from the **rail loading rack enclosed VCU** shall not exceed the limits listed in the above summary table (Colorado Construction Permit 88AD012, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Sections II.A.6 and Part C, Section X to increase emissions as indicated on the APEN received on June 4, 2019, red-lined on August 28, 2019). Compliance with the annual limits shall be monitored by calculating emissions monthly using the emission factors included in the above summary table (NO_X from April 2019 performance test and CO from manufacturer), the monthly quantity of petroleum products loaded (as required by Condition 24.6.1), the monthly number of ethanol rail cars unloaded (as required by Condition 24.11 and the monthly quantity of pilot gas combusted (as required by Condition 24.10) in the following equations:

Emissions = emissions from loading petroleum products + emissions from ethanol deaerators + emissions from depressurizing ethanol rail cars + emissions from pilot assist gas combustion

Emissions from loading petroleum products

NO_X/CO (tons/mo) = [NO_X/CO EF (lb/MMBtu) x L_L (lbs/10^3 gal) x monthly materials loaded (10^3 gal/mo) x heating value of material loaded (Btu/lb) x (MMBtu/10^6 Btu)]/2000 lb/ton

L_L (lb/10^3 gal) = 12.46 x SPM/T

Where: LL = loading loss (lb/10^3 gal), from AP-42, Section 5.2 (dated 6/08), equation 1
S = saturation factor (per Table 5.2-1 of AP-42), equals 1 per August 4, 2021 minor mod application.
P = true vapor pressure of liquid loaded, psia
M = molecular weight of vapors (lb/lbmole)
T = temperature of bulk liquid loaded (° R)
19,300 Btu/lb = heating value of diesel (AP-42, Section 3.3 (dated 10/96), Table 3.3-1, footnote c)
20,300 Btu/lb = heating value of gasoline (AP-42, Section 3.3 (dated 10/96), Table 3.3-1, footnote c). To be used for jet fuel as well.

Monthly emissions from loading shall be calculated using the monthly average vapor pressure and temperature of the liquids loaded for the monthly period. Constant vapor molecular weights of 66, 80 and 130 lb/lbmole for gasoline, jet fuel and distillates, respectively, shall be used in the monthly emission calculations.

Emissions from ethanol deaerators

NO_X/CO (tons/mo) = [NO_X/CO EF (lb/MMBtu) x number of ethanol rail cars unloaded (rail cars/mo) x

981 scf/rail car x (MMscf/10^6 scf) x 113 MMBtu/MMscf]/2000 lb/ton

Where: 981 scf/rail car = volume of vapor generated by ethanol deaerator, calculated by dividing mass of N_2 entrained in ethanol liquid (75.56 lb/rail car) divided by the vapor density (0.077 lb/scf), both of which were determined by HYSYS runs
113 MMBtu/MMscf = vapor stream heating value was calculated from the vapor composition (determined by HYSYS runs) by multiplying the individual component fractions by the gross heating value.

Emissions from depressurizing ethanol rail cars

NO_X/CO (tons/mo) = [NO_X/CO EF (lb/MMBtu) x number of ethanol rail cars unloaded x VOC EF (lb/rail car)/0.121 lb/scf x 2,540 Btu/scf x MMBtu/10^6 Btu]/2000 lb/ton

Where VOC EF (lb/rail car) = appropriate monthly emission factor from Condition 24.1.1.4
0.121 lb ethanol/scf = vapor density
2,540 Btu/scf = vapor stream heating value was calculated from the vapor composition (determined by HYSYS runs) by multiplying the individual component fractions by the gross heating value.

Emissions from pilot/assist gas combustion

NO_X/CO (tons/mo) = [NO_X/CO EF (lb/MMBtu) x monthly pilot/assist gas combusted (MMBtu/mo)]/2000 lb/ton

Monthly NO_X and CO emission shall be calculated by the end of the subsequent month. Monthly emissions shall be used in twelve-month rolling totals to monitor compliance with the annual limitations. Each month new twelve month totals shall be calculated using the previous twelve months data.

24.1.3 For APEN reporting and fee purposes, PM, PM_{10} and SO_2 emissions from the **rail loading rack enclosed VCU** shall be calculated monthly. Monthly emissions shall be summed to obtain calendar year emissions for APEN reporting purposes. Monthly emissions shall be calculated as follows:

24.1.3.1 PM and PM_{10} emissions shall be calculated monthly using the emission factors included in the table below, the monthly quantity of material loaded (as required by Condition 24.6), the monthly number of ethanol rail cars unloaded (as required by Condition 24.11) and the monthly quantity of pilot/assist gas consumed (as required by Condition 24.10) in the equations in Condition 24.1.2.

Fuel	PM/PM_{10} Emission Factor (lb/MMBtu)	Emission Factor Source
Natural Gas	7.45 x 10^{-3}	AP-42, Section 1.4 (dated 7/98), Table 1-4-2, converted to lb/MMBtu by dividing by 1,020 Btu/scf per footnote a.
Propane	7.65 x 10^{-3}	AP-42, Section 1.5 (dated 7/08), Table 1-5-1, converted to lb/MMBtu by dividing by 91.5 MMBtu/10^3 gal per footnote a.

24.1.3.2 Monthly emissions of SO_2 shall be determined by summing daily SO_2

emissions (as required by Condition 24.3).

24.2 The **rail loading rack enclosed VCU** is subject to 40 CFR Part 60, Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

The permittee has demonstrated that the fuel gas streams combusted in the flare meet the requirements in §60.107a(a)(3)(iv). The demonstration was submitted to EPA on September 5, 2018 and the demonstration met the requirements in §60.107(b). Fuel gas streams that meet the requirements in §60.107a(a)(3)(iv) are exempt from the sulfur monitoring requirements in NSPS Subpart J.

The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section). (60.107a(b)(2))

No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section. (60.107a(b)(3))

24.3 Sulfur dioxide emissions from the **rail loading rack enclosed VCU** shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1of this permit.

For purposes of monitoring compliance with the Colorado Regulation No. 1 SO_2 limit, daily SO_2 emissions from the **rail loading rack enclosed VCU** shall be calculated as follows:

SO_2 emissions from VCU (lb/day) = SO_2 from loading petroleum products (lb/day) + SO_2 from pilot gas (lb/day)

<u>SO_2 from loading</u>

SO_2 (lb/day) = [EF (lb/MMscf) x L_L (lbs/10^3 gal) x daily materials loaded (10^3 gal/day) x MMscf/10^6 scf /MW (lb/lb-mol) x 385.3 scf/lb-mol]

Where: L_L = loading losses (see equation in Condition 24.1.2)
MW = vapor molecular weight, for distillate (MW = 130 lb/lb-mole), for gasoline (MW = 66 lb/lbmole), for jet fuel (80 lb/lbmole)
EF = 0.2325 lb/MMscf, which is based on an H_2S concentration of 1.4 ppmv and calculated in accordance with the following equation:

EF (lb/MMscf) = 1.4 scf H_2S/10^6 scf x lb-mole H_2S/385.3 scf H_2S x lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2 x 10^6 scf/MMscf

Daily emissions from loading shall be calculated using the monthly average vapor pressure and temperature of the liquids loaded for the monthly period. Constant vapor molecular weights of 66, 80 and 130 lb/lbmole for gasoline, jet fuel and distillates, respectively, shall be used in the monthly emission calculations.

<u>SO_2 from pilot/assist gas</u>

Note that natural (city) gas and propane are used for pilot/assist gas

SO_2 (lb/day) = EF (lb/MMscf) x 83.3 scf/hr x daily hours of operation x MMscf/10^6 scf

Where: EF = 0.6 lb/MMscf (from AP-42, Section 1.4 (dated 7/98), Table 1.4-2)

Note that SO_2 emissions from the ethanol deaerators and depressurizing ethanol rail cars are assumed to be negligible.

24.4 These sources are subject to RACT as follows:

24.4.1 Petroleum product loading at the **rail loading rack** is subject to the requirements in Colorado Regulation No. 24, Part B, Sections IV.C.2, IV.C.4.a and VII as set forth in Conditions, 41.3, 41.4 and 44 of this permit.

24.4.2 The **rail loading rack VCU** is subject to the requirements in Colorado Regulation No. 24, Part B, Section VI.B.6 as set forth in Condition 43.2.5. In the absence of credible evidence to the contrary, compliance with the requirements in Regulation No. 24, Part B, Section VI.B.6 is presumed provided the VCU meets the requirements in Condition 24.8.

24.4.3 Ethanol unloading at the rail loading rack is subject to RACT for VOC emissions (Colorado Regulation No. 3, Part B, Section II.D.2.a and Regulation No. 7, Part A, Section II.C.2)). RACT for ethanol unloading at the **rail unloading rack** shall be met by routing vapors from the ethanol deaerators and depressurizing rail cars to the rail loading rack VCU. The rail loading rack VCU shall meet the requirements in Conditions 24.5 and 24.8.

24.5 The **rail loading rack** is subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 53 of this permit.

24.6 Loading/Unloading throughput is subject to the following requirements:

24.6.1 Petroleum products loaded through the **rail loading rack** shall not exceed the following limitations (Colorado Construction Permit 88AD012, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Sections II.A.6 and Part C, Section X to revise throughputs as indicated on the APEN received on June 4, 2019, red-lined on August 28, 2019):

24.6.1.1 Gasoline and/or other products with a TVP less than or equal to 5.85 psia at 50 º F loaded shall not exceed 3,640,000 bbl/year.

24.6.1.2 Jet fuel and/or other products with a TVP less than or equal to 1.3 psia at 50 º F shall not exceed 546,000 bbl/year.

24.6.1.3 Distillates and/or other products with a TVP less than or equal to 0.05 psia at 50 º F shall not exceed 1,500,000 bbl/year.

24.6.2 Unloading of ethanol from the rail loading rack shall not exceed 340,000 bbl/year (Colorado Construction Permit 88AD012, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Sections II.A.6 and Part C, Section X to revise throughputs as indicated on the APEN received on June 4, 2019, red-lined on August 28, 2019).

Compliance with the annual throughput limits shall be monitored by recording the quantity of petroleum products (gasoline, jet fuel and distillate) loaded and the quantity of ethanol unloaded daily. Daily quantities of materials loaded and unloaded shall be summed to determine monthly values. Monthly quantities of gasoline, jet fuel and distillates loaded and ethanol unloaded shall be used in twelve month rolling totals to monitor compliance with the annual limitations. Each month new twelve month totals shall be calculated using the previous twelve months data.

24.7 The **rail rack enclosed VCU** is subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. Compliance with the opacity limits shall be monitored as set forth in Condition 35.7.

24.8 The temperature in the **rail loading rack VCU** combustion zone is subject to the following requirements:

24.8.1 The temperature in the **rail loading rack VCU** combustion zone shall not be less than 1,299 ºF on a 6-hour rolling average. (40 CFR Part 63 Subpart CC §63.550(a) via Subpart R §§63.425(b) and 63.427(a)(3) and Construction Permit 88AD012, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, to replace the flare with a VCU and to include the operating parameter in accordance with modification applications submitted on June 14, 2018 and October 8, 2009). The combustion chamber temperature shall be monitored in accordance with the CAM plan in Appendix N and the CAM requirements in Condition 60 (as required by Condition 23.13).

24.8.2 When a value is calculated on a 6-hour rolling average that is below 1,299 °F and gasoline was being loaded during the period, the occurrence will be noted and reported to the Division in the Refinery MACT (40 CFR Part 63 Subpart CC) periodic report and the semi-annual operating permit report for that period. When a value is calculated on a 6 hour rolling average that is below 1,299 °F and materials other than gasoline are being loaded (distillate and/or jet fuel) or ethanol is being unloaded during the period, the occurrence will be noted and reported to the Division in the semi-annual operating permit report.

24.8.3 The minimum temperature value specified in Conditions 24.8.1 and 24.8.2 shall be revised based on subsequent performance tests upon approval by the Division as required by Condition 24.12, to verify compliance with the rail loading rack limit in Condition 24.5 (40 CFR Part 63 Subpart CC) and the 98% control efficiency used to calculate emissions in Condition 24.1.

24.9 The **rail rack enclosed VCU** is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

24.10 Pilot and assist gas consumption in the **rail rack enclosed VCU** shall not exceed the following limitations (Colorado Construction Permit 88AD012, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Sections II.A.6 and Part C, Section X to include heat input limits on pilot and assist gas as indicated on the APEN received on June 4, 2019, red-lined on August 28, 2019):

24.10.1 Natural gas (city) consumption shall not exceed 48,081 MMBtu/yr.

24.10.2 Propane consumption shall not exceed 10,194 MMBtu/yr.

Compliance with the annual limitations shall be monitored by recording natural (city) gas and propane pilot/assist gas consumption daily using the flow meter. Daily natural (city) gas and propane values shall be summed to get monthly pilot/assist gas usage. The Btu content of natural (city) gas and propane shall be based on heat contents of 1020 Btu/scf and 2,470 Btu/scf, respectively. Monthly quantities of natural (city) gas and propane shall be used in twelve month rolling totals to monitor compliance with the annual limitations. Each month new twelve month rolling totals shall be calculated using the previous twelve months data.

24.11 The number of ethanol rail cars unloaded shall be monitored and recorded monthly. Monthly quantities of rail cars loaded will be used to calculate emissions as required by Conditions 24.1.1, 24.1.2 and 24.1.3.1.

24.12 A compliance test shall be conducted as specified in the paragraphs below to monitor compliance with the rail loading rack limit in Condition 24.5 (total organic compound emissions not to exceed 10 mg/l of gasoline loaded), to verify the 98% control efficiency used in the emission calculations in Condition 24.1 and ro revise the temperature limit in Condition 24.8. Performance tests shall be conducted in accordance with the appropriate EPA Test Methods and the provisions in 40 CFR Part 63 Subparts CC and R (§§63.650(a) and 425(a) through (c)).

If the renewal permit is issued on or before June 1, testing must be completed by September 30 of that year. If the renewal permit is issued after June 1, testing must be completed by September 30 of the following year. Frequency of testing thereafter shall be every five (5) years.

The compliance test must be conducted in accordance with the most recent version of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/sites/default/files/AP_Compliance-Test-Manual.pdf), including deadlines for preparation and submittal of the protocol for Division review and approval and for submittal of the test report. All compliance testing must be approved by the Division prior to conducting the test.

During each compliance test required by this Condition 24.12, the compliance assurance monitoring (CAM) indicator minimum value (combustion zone temperature) shall be revised.

Within 60 days of completion of each compliance test required by this permit condition, the permittee shall submit for approval a revised compliance assurance monitoring (CAM) indicator minimum value (combustion zone temperature) and begin monitoring under the proposed value. The proposed minimum value submittal shall include the justification and supporting data for the proposed CAM indicator. In addition, the permittee shall submit with the proposed CAM indicator a minor modification application to revise the permit to incorporate the proposed minimum value for the CAM indicator (combustion zone temperature) into Conditions 24.8 and 60 (CAM requirements) and Appendix N (CAM plan) of this permit.

24.13 The rail loading rack is subject to the compliance assurance monitoring (CAM) requirements with respect to the VOC emission limitation identified in Condition 24.1.1. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plan in Appendix N.

25. Truck Loading Rack (Denver Products Terminal)

R102 (AIRS Pt 069) – Truck Loading Rack and Flare

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	25.1		7.45×10^{-3}	Recordkeeping Calculation	Monthly
PM_{10}					
SO_2			See Condition 25.1.3.2		Daily, Monthly
	25.2	0.3 lb SO_2/bbl/day of oil processed	See Condition 25.2	Recordkeeping Calculation	Daily, Monthly
NOx	25.1	5.1 tons/year	0.068 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC		26.6 tons/year	See Condition 25.1.1		
RACT	25.3	See Condition 25.3		See Condition 25.3	
MACT	25.4	See 40 CFR Part 63 Subpart R (Condition 52)		See 40 CFR Part 63 Subpart R (Condition 52)	
CO	25.1	23.3 tons/year	0.31 lb/MMBtu	Recordkeeping Calculation	Monthly
Throughput	25.5	15,000,000 bbl gasoline/year 10,000,000 bbl petroleum distillate/year		Recordkeeping	Daily, Monthly
Opacity	25.6	Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Visual Inspection	Daily
Flare Operation	25.7	See Condition 57			
NSPS	25.8	General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60, Subparts A (Condition 56) and XX (Condition 50)	
		Specific Requirements – Subpart XX (Condition 50)			
MACT	25.9	See 40 CFR Part 63, Subpart GGGGG (Condition 66)		See 40 CFR Part 63 Subpart GGGGG (Condition 66)	
Hours of Operation	25.10			Recordkeeping	Monthly
BWON	25.12	See 40 CFR Part 61 Subpart FF (Condition 65)		See 40 CFR Part 61 Subpart FF (Condition 65)	
Use of a Temporary Flare	25.15	A Temporary Flare May be Used for Up to 2 Weeks During any 12-Month Rolling Period. The Temporary Flare shall Meet the Design and Operating Requirements in Condition 25.15		See Condition 25.15	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Flare Stack Height Requirement	25.16	The height of the flare shall be no less than 35 feet.		See Condition 25.16	
CAM Requirements	25.17	See Condition 25.17		See Condition 25.17	

F203 (AIRS Pt 162) – Truck Loading Rack Drains

SU0001 (AIRS pt 163) – Truck Loading Rack Sump (8,000 gal, underground)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	25.1	F203 – 3.9 tons/year	0.064 lb/hr/drain	Recordkeeping Calculation	Monthly
		SU0001 – 0.04 tons/year	TankESP, based on AP-42, Chapter 7.1 (June 2020)	Recordkeeping Calculation	Monthly
Throughput	25.5	SU0001: 160,000 gallons/year of wastewater		Recordkeeping	Monthly
SU0001 - RACT	25.11	See Condition 25.11		See Condition 25.11	
BWON	25.12	See 40 CFR Part 61 Subpart FF (Condition 65)		See 40 CFR Part 61 Subpart FF (Condition 65)	
SU0001 – Carbon Canister Breakthrough	25.13	Breakthrough Defined as 5 ppm Benzene		See Condition 25.13	
F203 -BWON Program Enhancements – Consent Decree Requirements	25.14	See Appendix G		See Appendix G	

25.1 Emissions of air pollutants from these sources are subject to the following limitations:

25.1.1 VOC emissions from the **truck loading rack and flare (R102)** shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to revise emissions as indicated on the APEN received on October 19, 2021) Compliance with the annual limits shall be monitored as follows:

25.1.1.1 Monthly emissions **from loading gasoline** shall be calculated using the monthly quantity of liquids loaded (as required by Condition 25.5.1) in the below equations:

VOC (tons/mo) = [10 mg/l loaded x monthly quantity loaded (gal/mo) x 3.7854 l/gal x 1 g/1000 mg x 1 lb/453.6 g]/2000 lb/ton

Where: 10 mg/l loaded is the MACT R emission limit for gasoline loading (40 CFR Part 63 Subpart R § 63.422(b)

For periods when gasoline is being loaded and the pilot flame in the truck loading rack flare is not present, VOC emissions shall be calculated using the loading loss equation in Condition 25.1.1.2, with a control efficiency of 0%.

Emissions shall be calculated using the average vapor pressure and temperature of the liquids loaded during the period that the flare pilot flame is out and a constant vapor molecular weight of 66 lb/lbmole. Records shall be maintained of periods when the flare pilot flame is not present and gasoline is being loaded.

25.1.1.2 Monthly VOC emissions **from distillate loading** shall be calculated using the monthly quanitity of distillate loaded (as required by Condition 25.5.1.2) in the following equation:

VOC (tons/mo) = [LL (lb/10^3 gal) x monthly materials loaded (10^3 gal/mo) x (1 - (control efficiency/100))]/2000 lb/ton

L_L = 12.46 x SPM/T

Where: LL = loading loss (lb/10^3 gal), from AP-42, Section 5.2 (dated 6/08), eqn 1
S = saturation factor (per Table 5.2-1 of AP-42)
P = true vapor pressure of liquid loaded, psia
M = molecular weight of vapors (lb/lbmole)
T = temperature of bulk liquid loaded (º R)

A control efficiency of 95% may be used in the above equation for the flare provided it meets the flare requirements in Condition 25.7.

Monthly emissions shall be calculated using the monthly average vapor pressure and temperature of the liquids loaded for the monthly period and a constant vapor molecular weight of 130 lb/lbmole.

For periods when distillate products are being loaded and the pilot flame in the truck loading rack flare is not present, VOC emissions shall be calculated using a control efficiency of 0%.

Emissions shall be calculated using the average vapor pressure, vapor molecular weight and temperature of the liquids loaded during the period that the flare pilot flame is out. Records shall be maintained of periods when the flare pilot flame is not present and distillate products are being loaded.

25.1.1.3 Monthly emissions **from pilot gas consumption** shall be calculated using an emission factor of 5.5 lb/MMscf (from AP-42, Section 1.4, dated 7/98, Table 1.4-2) and hours of flare operation (as required by Condition 25.10) in the following equation:

VOC (tons/mo) = [EF (lb/MMBtu) x 83.3 scf/hr x monthly hours of operation x 1,020 MMBtu/MMscf x 1 MMscf/10^6 scf]/2000 lb/ton

Where: 83.3 scf/hr = design rate of pilot
EF = 0.0987 lb/MMBtu (from Xcel gas composition data, Denver area high pressure line, December 2017, 95% control efficiency assumed)
Hours of operation as required by Condition 25.10.

Monthly emissions shall be calculated by the end of the subsequent month. Monthly emissions calculated in accordance with Conditions 25.1.1.1 through 25.1.1.3 shall be summed together and used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month total shall be estimated using the previous twelve months data.

25.1.2 NO_X and CO emission from the **truck loading rack and flare (R102)** shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to revise emissions as indicated on the APEN received on October 19, 2021) Compliance with the annual limits shall be monitored by calculating emissions monthly using the above emission factors (from AP-42, Section 13.5 (dated 9/91), Table 13.5-1) and either the monthly quantity of liquids loaded (as required by Condition 25.5.1) or hours of operation (as required by Condition 25.10) in the below equations

NO_X/CO (tons/mo) = NO_X/CO from loading + NO_X/CO from pilot gas consumption

<u>NO_X/CO from loading</u>

NO_X/CO (tons/mo) = [EF (lb/MMBtu) x L_L (lbs/10^3 gal) x monthly materials loaded (10^3 gal/mo) x heating value of material loaded (Btu/lb) x (MMBtu/10^6 Btu)]/2000 lb/ton

L_L (lb/10^3 gal) = 12.46 x SPM/T

Where: LL = loading loss (lb/10^3 gal), from AP-42, Section 5.2 (dated 6/08), equation 1
S = saturation factor (per Table 5.2-1 of AP-42), equals 1 per August 4, 2021 minor mod application.
P = true vapor pressure of liquid loaded, psia
M = molecular weight of vapors (lb/lbmole)
T = temperature of bulk liquid loaded (° R)
19,300 Btu/lb = heating value of diesel (AP-42, Section 3.3 (dated 10/96), Table 3.3-footnote c)
20,300 Btu/lb = heating value of gasoline (AP-42, Section 3.3 (dated 10/96), Table 3.3-footnote c)

Monthly emissions from loading shall be calculated using the monthly average vapor pressure and temperature of the liquids loaded for the monthly period. Constant vapor molecular weights of 66 and 130 lb/lbmole for gasoline and distillates, respectively, shall be used in the monthly emission calculations.

<u>NO_X/CO from pilot gas consumption</u>

NO_X/CO (tons/mo) = [EF (lb/MMBtu) x 83.3 scf/hr x monthly hours of operation (as required by

Condition 25.10) x 1020 Btu/scf x 1 MMBtu/10^6 Btu]/2000 lb/ton

Monthly emission shall be calculated by the end of the subsequent month. Monthly emissions from loading and pilot/assist gas consumption shall be summed together and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

25.1.3 For APEN reporting and fee purposes, PM, PM_{10} and SO_2 emissions from the **truck loading rack and flare (R102)** shall be calculated monthly. Monthly emissions shall be summed to obtain calendar year emissions for APEN reporting purposes. Monthly emissions shall be calculated as follows:

25.1.3.1 PM and PM_{10} emissions shall be calculated monthly using the emission factors included in the above summary table (from AP-42, Section 1.4 (dated 7/98), Table 1.4-2, converted to lb/MMBtu based on a heat content of 1020 Btu/scf per footnote a), the monthly quantity of material loaded (as required by Condition 25.5.1) and monthly hours of operation (as required by Condition 25.10) in the equations in Condition 25.1.2.

25.1.3.2 Monthly emissions of SO_2 shall be determined by summing daily SO_2 emissions (as required by Condition 25.2).

25.1.4 VOC emissions from the **truck loading rack drains (F203)** shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include emission limits for drains as requested on the APEN received on June 23, 2017, red-lined on November 13, 2017.) Compliance with the annual limit shall be monitored by calculating emissions monthly using the number of hours in the month and the emission factor in the above summary table (from AP-42, Section 5.1 (dated 4/15), Table 5.1-4) in the equation below:

VOC (ton/mo) = [EF (lb/drain-hr) x No. of Drains x No. of hours in the month]/2000 lb/ton

Note that the control efficiencies listed in the table below can be applied to the above calculations provided the requirements in Condition 25.12 have been met for the controlled drains.

Control[1]	Control Efficiency	Source
Water seals	50%	EPA-450/3-85-001a, February 1985, “VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards”, page 4-9
Gasketed and Sealed Lids	23%	EPA-450/3-85-001b, December 1987, “VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Promulgated Standards”, page 2-23

[1]Permitted emissions include 18 drains. 5 drains (truck bay area drains) are equipped with water seals and 7 are equipped with gasketed and sealed lids (truck bay drain funnels and clean-out and inspection ports).

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

25.1.5 VOC emissions from the **truck loading rack sump (SU0001)** shall not exceed the limits listed in the above summary table (Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include emission limits for drains as requested on the APEN received on June 23, 2017, red-lined on November 13, 2017). Compliance with the annual limit shall be monitored by calculating emissions monthly using the monthly throughput (as required by Condition 25.5.2) and a TankESP version based on the June 2020 version of AP-42, Chapter 7.1. Note that if a new version of AP-42, Chapter 7.1 is published, Suncor may be required to modify this condition to include the new calculation methodologies to calculate emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total. Each month a new twelve month total shall be calculated using the previous twelve months data.

25.2 Sulfur dioxide emissions from the **truck loading rack and flare (R102)** shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit.

For purposes of monitoring compliance with the Colorado Regulation No. 1 SO_2 limit, daily SO_2 emissions from the **truck loading rack flare (R102)** shall be calculated as follows:

SO_2 emissions from flare (lb/day) = SO_2 from loading (lb/day) + SO_2 from pilot gas (lb/day)

<u>SO_2 from loading</u>

SO_2 (lb/day) = [EF (lb/MMscf) x L_L (lbs/10^3 gal) x daily materials loaded (10^3 gal/day) x MMscf/10^6 scf /MW (lb/lb-mol) x 385.3 scf/lb-mol]

Where: L_L = loading losses (see equation in Condition 25.1.2)
MW = vapor molecular weight, for distillate (MW = 130 lb/lb-mole), for gasoline (MW = 66 lb/lbmole)
EF = 0.2325 lb/MMscf, which is based on an H_2S concentration of 1.4 ppmv and calculated in accordance with the following equation:

EF (lb/MMscf) = 1.4 scf H_2S/10^6 scf x lb-mole H_2S/385.3 scf H_2S x lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2 x 10^6 scf/MMscf

Daily emissions from loading shall be calculated using the monthly average vapor pressure and temperature of the liquids loaded for the monthly period. Constant vapor molecular weights of 66 and 130 lb/lbmole for gasoline and distillates, respectively, shall be used in the monthly emission calculations.

<u>SO_2 from pilot gas</u>

Note that natural (city) gas is used for pilot/assist gas

SO_2 (lb/day) = EF (lb/MMscf) x 83.3 scf/hr x daily hours of operation x MMscf/10^6 scf

Where: EF = 0.6 lb/MMscf (from AP-42, Section 1.4 (dated 7/98), Table 1.4-2)
Hours of operation as required by Condition 25.10

25.3 The **truck loading rack (R102)** is subject to Colorado Regulation No. 24, Part B, Sections IV.C.2, IV.D.2.a, and VII as set forth in Conditions 41.3, 41.5, and 44 of this permit.

25.4 The **truck loading rack (R102)** is subject to the requirements of 40 CFR Part 63, Subpart R as set forth in Condition 52 of this permit.

25.5 Throughput through these sources are subject to the following limitations:

25.5.1 The **truck loading rack and flare (R102)** is limited to throughputs as follows:

(Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to revise the throughput limits as indicated on the APEN received on July 25, 2013)

25.5.1.1 Throughput of gasoline (all grades of gasoline, including blending components, having an annual average RVP of 13.0 psia or lower and a maximum monthly average RVP of 15.5 psia or lower) shall not exceed 15,000,000 bbl/year.

25.5.1.2 Throughput of petroleum distillates (including diesel fuel, bio-diesel and kerosene oil that has a true vapor pressure ≤ 0.029 psia at 100 ºF) shall not exceed 10,000,000 bbl/year.

Compliance with the annual throughput limits shall be monitored by recording the throughput of gasoline and petroleum distillates daily. Daily quantities of materials loaded shall be summed to determine monthly values. Monthly throughputs of gasoline and petroleum distillates shall be used in twelve month rolling totals to monitor compliance with the annual limitations. Each month new twelve month rolling totals shall be calculated using the previous twelve months data. Records of the vapor pressures of the materials loaded shall be maintained and made available to the Division upon request.

25.5.2 Throughput of wastewater through the truck loading rack sump (SU0001) shall not exceed 160,000 gallons/year (Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to revise the throughput limits as indicated on the APEN received on June 23, 2017, red-lined on November 13, 2017) Compliance with the annual throughput limit shall be monitored by determining the quantity of wastewater processed through the sump monthly. Monthly wastewater throughput shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

25.6 The **truck loading rack flare (R102)** is subject to the following opacity limit: No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes. (Colorado Regulation No. 1, Section II.A.5).

In the absence of credible evidence to the contrary, compliance with above opacity limit shall be presumed provided the monitoring in Condition 57.9 indicates compliance with the visible emission requirement in Condition 57.1. In the absence of credible evidence to the contrary, for periods when the monitoring in Condition 57.9 indicates non-compliance with the visible emission requirements in Condition 57.1, the flare shall be considered out of compliance with the opacity limit in this Condition 25.6 for the entire non-compliance period, unless a Method 9 observation is conducted that indicates compliance.

25.7 The **truck loading rack flare (R102)** is subject to the provisions set forth in Condition 57 of this permit.

25.8 This **truck loading rack (R102)** is subject to the NSPS requirements as follows:

25.8.1 This source is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

25.8.2 This source is subject to the specific requirements for bulk gasoline terminals in 40 CFR Part 60, Subpart XX, as set forth in Condition 50 of this permit.

25.9 This **truck loading rack (Denver Products Terminal)** is subject to the requirements of 40 CFR Part 63, Subpart GGGGG, as set forth in Condition 66 of this permit.

25.10 Hours of operation for the **truck loading rack flare (R102)** shall be monitored and recorded daily. Daily hours of operation shall be summed to determine monthly hours of the operation. Hours of operation shall be used to calculate emissions from pilot gas consumption as required by Conditions 25.1.1.3, 25.1.2 and 25.2.

25.11 The **truck loading rack sump (SU0001)** is subject to the requirements in Regulation No. 24, Part B, Section I.A as set forth in Condition 39.1 of this permit.

25.12 The **truck loading rack flare (R102) and associated piping from the meter prover to the flare, the controlled truck loading rack drains (F203) and the truck loading rack sump (SU0001)** are subject to the requirements of 40 CFR Part 61 Subpart FF, as set forth in Condition 65 of this permit.

25.13 The permittee shall monitor for breakthrough between the primary and secondary carbon canisters associated with the **truck loading rack sump (SU0001)** at times there is actual flow to the carbon canister in accordance with the frequency specified in 40 CFR Part 61 Subpart FF §61.354(d) (Condition 65.30). (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate Consent Decree (H-01-4430) requirements related to carbon canisters. Consent Decree (H-01-4430), Paragraph 91):

25.13.1 Breakthrough from carbon canisters shall be defined as any reading equal to or greater than 5 ppm benzene.

25.14 The **controlled truck loading rack drains (F203)** are subject to the BWON Program Enhancements in the Consent Decree (H-01-4430) as set forth in Appendix G of this permit. The BWON Program Enhancement monitoring requirements, as set forth in Appendix G of this permit, include the following:

25.14.1 The permittee shall conduct monthly visual inspections of all water traps used for BWON control within the refinery's individual drain systems. (Paragraph 117(a))

25.15 A temporary flare may be used in place of the **Truck Loading Rack Flare**, provided the following requirements are met:

(Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to allow the use of a temporary flare as requested in the August 4, 2021 minor modification application to replace the flare tips)

25.15.1 The temporary flare shall meet the emission limits, operating and regulatory requirements for the **Truck Loading Rack Flare** set forth in this Condition 25, in accordance with methods set forth in this Condition 25, except as specified in this Condition 25.15. Emissions from the temporary flare, including pilot gas combustion shall be included in the monthly and daily emission calculations for the **Truck Loading Rack Flare** in Conditions 25.1 and 25.2, except as follows:

25.15.1.1 The design pilot flow rate of the temporary flare shall be used to calculate emissions from pilot gas consumption using the equations in Conditions 25.1.1.3, 25.1.2 and 25.2

25.15.1.2 If the temporary flare uses propane for pilot fuel, the following changes to emission calculations methodologies will be used:

a. An emission factor of 28.9 lb/MMscf shall be used in the emission calculations required by Condition 25.2. The emission factor is based on a propane H_2S content of 174 ppm.

b. A propane heat content of 21,580 Btu/lb shall be used in the emission calculations required by Condition 25.1.2. The heat content is based on a propane heat value of 91.5 MMBtu/10^3 gal and a propane density of 4.24 lb/gal (per AP-42, Section 1.5 (dated 7/2008), Table 1.5-1, footnote a and AP-42, Appendix A)

c. VOC emissions shall be calculated as specified in this condition and summed together with emissions estimated in accordance with the procedures in Conditions 25.1.1.1 through 25.1.1.3 to determine total monthly emissions from the truck loading rack flare, when a temporary flare is used during the month.

VOC (ton/month) = pilot flow (scf/hr) x hours of operation x lb-mole/385.3 scf x 44.1 lb/lb-mole x (1-control efficiency).

A control efficiency of 95% may be used in the above equation provided the temporary flare meets the requirements in Condition 25.7.

For periods when products are being loaded and the pilot flame in the temporary flare is not present, VOC emissions shall be calculated using a control efficiency of 0%. Records shall be maintained of periods when the temporary flare pilot flame is not present and products are being loaded.

25.15.2 The temporary flare shall not be operated while the **Truck Loading Rack Flare** is in operation.

25.15.3 The temporary flare shall not be operated for more than two weeks (336 hours) in any twelve month rolling period. Records of the hours of operation for the temporary flare shall be maintained and made available to the Division upon request.

25.15.4 The temporary flare shall combust either natural gas or propane as pilot gas. The heat input for pilot gas usage from the temporary flare shall not exceed 18.3 MMBtu in any twelve month rolling period.

25.15.5 The permittee shall conduct a demonstration on the temporary flare in accordance with the requirements in 40 CFR Part 60, Subpart XX § 60.503(e) (Condition 50.14). Records of the demonstration shall be maintained and made available to the Division upon request.

25.15.6 Loading of products at the Truck Loading Rack (gallons per minute) shall not exceed the design rate of the temporary flare. The manufacturer’s specification sheet for the temporary flare shall be maintained and made available to the Division upon request.

25.16 The height of the permanent flare shall be no less than 35 feet. (Colorado Construction Permit 86AD450, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to reflect the stack height used in the modeling analysis for the August 4, 2021 minor modification application to replace the flare tips).

25.17 The truck loading rack is subject to the compliance assurance monitoring (CAM) requirements with respect to the VOC emission limitation identified in Condition 25.1.1, Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plan in Appendix N.

26. Groundwater Treatment Unit with Air Strippers – A1

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	26.1	9.90 tons/year	Material Balance	Recordkeeping and Calculation	Monthly
Location	26.2				
Water Processed	26.3			Recordkeeping	Daily
Opacity	26.4	Not to exceed 20%, except as provided for below		See Condition 26.4.	
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
RACT	26.5	See Condition 26.5.		See Condition 26.5.	

26.1 Emissions of air pollutants shall not exceed the limitation listed in the table above. (Colorado Construction Permit 88AD388) The concentration of contaminants in the inlet and outlet streams shall be monitored monthly. Monitoring of the inlet and outlet contaminant concentration shall be conducted on the same day. Monthly contaminant concentration monitoring shall be conducted at least 10 calendar days apart. (Colorado Construction Permit 88AD388, as modified under the provisions of Section I, Condition 1.3 to require that inlet and outlet contaminant concentrations be monitored) Monthly emissions from the Air Strippers shall be calculated by the end of the subsequent month using the monthly quantity of water processed and the inlet and outlet contaminant concentrations (emissions assumed to be the difference between the inlet and outlet). Monthly emissions shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

26.2 The air stripper shall not be moved to another area at Suncor or the Colorado Refinery Company until the volatile organic compound emission limits are revised and the Division has been notified in writing. (Construction Permit 88AD388)

26.3 The permittee shall monitor and record daily average contaminated water processing rate. (Colorado Construction Permit 88AD388) Daily water quantities of water treated shall be summed to determine the monthly quantity of water processed. Monthly quantities of water processed shall be used to calculate emission as specified in Condition 26.1.

26.4 This source is subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. Provided this emission source operates solely as an air stripper and has no associated combustion activities, and absent credible evidence to the contrary, this source is presumed to be in compliance with this condition.

26.5 This activity is subject to Colorado Regulation No. 24, Part B, Section III. No person shall dispose of volatile organic compounds by evaporation or spillage unless RACT is utilized. The Division has determined that “no control” represents RACT for activity.

27. Process Heater H-2101 (Rated at 331 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
PM	27.1	10.70 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping Calculation	Monthly
	27.2	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM_{10}	27.1	10.70 tons/year	7.45 x 10^{-3} lb/MMBtu	Recordkeeping Calculation	Monthly
SO_2	27.1	10.20 tons/year	See Condition 27.1.2	Recordkeeping Calculation	Monthly
	27.3	<u>NSPS Subpart J Requirement:</u> Fuel gas shall not contain H_2S in excess of 0.10 gr/dscf, on a 3-hour rolling average[1]		Continuous Monitoring System	Continuous
	27.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 27.4	Recordkeeping Calculation	Daily Monthly
NO_X	27.5	0.04 lb/MMBtu, on a 3-hr rolling average		Continuous Emission Monitor	Continuous
	27.1	52.19 tons/year	CEMS		
CO		57.99 tons/year	CEMS		
VOC		7.74 tons/year	5.39 x 10^{-3} lb/MMBtu	Recordkeeping Calculation	Monthly
Fuel Use	27.6	2,899,560,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	27.7	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	27.8	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
RACT – Reg 3	27.9	See Condition 27.9.		See Condition 27.9.	
NSPS General Provisions	27.10	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Continuous Emission Monitoring System Requirements	27.11	See Condition 27.11		See Condition 27.11	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Restrictions on Relaxing Emission Limitations	27.12	See Condition 27.12		Certification	Annually
RACT – Reg. 7	27.13	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	27.14	Combustion Process Adjustment Requirements		See Condition 73	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

27.1 Emissions of air pollutants are subject to the following requirements:

27.1.1 PM, PM_{10} and VOC emissions shall not exceed the limits listed in the above summary table (Colorado Construction Permit 04AD0109). Compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above table (PM, PM_{10} and VOC from AP-42, Section 1.4, dated 7/98, Table 1.4-2, emission factors converted to lb/MMBtu by dividing by 1020 Btu/scf per footnote a) and the monthly fuel consumption (as required by Condition 27.6) in the following equation:

Emissions (tons/month) = [EF (lb/MMBtu) x fuel usage (MMBtu/mo)]/2000 lbs/ton

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

27.1.2 SO_2 emissions shall not exceed the limits listed in the above summary table (Colorado Construction Permit 04AD0109). Compliance with the annual limitation shall be monitored by calculating SO_2 emissions daily as described below.

Daily SO_2 emissions shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 27.3) and the daily fuel consumption (as required by Condition 58)

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

27.1.3 NOx emissions shall not exceed the limits listed in the above summary table (Colorado Construction Permit 04AD0109 snd Regulation No. 23, Section IV.F.3.). Compliance with the annual limits shall be monitored using the NO_X CEMS required by Condition 27.11 as follows:

For any hour is which fuel is fired in the heater, the permittee shall program the data acquisition and handling system to calculate lb/hr of NO_X emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass NO_X emissions (in lb/hr) shall be calculated using the following equation:

$E_h = F_d \times C_d \times MW/385.3 \times 10^{-6} \times (20.9/(20.9 - \%O_2)) \times H_g$

Where: E_h = mass emissions (lb/hr)
F_d = fuel factor, dry, scf/MMBtu (calculated from on-site analyzers)
C_d = NO_X concentration, dry basis, ppm
MW = NO_X molecular weight, 46.01 lb/mol
Q_d = volumetric flow rate, dry basis, scfm
$\%O_2$ = O_2 concentration, dry basis (from O_2 CEMS)
H_g = heat input rate (MMBtu/hr)

The resulting NO_X lb/hr value is then multiplied by the unit operating time for the heater for that hour to produce a NO_X lbs value. Hourly NO_X emissions (lbs) shall be summed and divided by 2000 to determine monthly NO_X emissions (in tons). In determining compliance with the annual emissions limitation, all periods of emissions must be included, including startups, shutdowns, emergencies and malfunctions.

Monthly emissions shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

27.1.4 CO emissions shall not exceed the limits listed in the above summary table (Colorado Construction Permit 04AD0109). Compliance with the annual limit shall be monitored using the CO CEMS required by Condition 27.11 as follows:

For any hour is which fuel is fired in the heater, the permittee shall program the data acquisition and handling system to calculate lb/hr of CO emissions in accordance with the requirements in Condition 59.1.1.3.b and 40 CFR Part 60.

Specifically hourly mass CO emissions (in lb/hr) shall be calculated using the following equation:

$E_h = F_d \times C_d \times MW/385.3 \times 10^{-6} \times (20.9/(20.9 - \%O_2)) \times H_g$

Where: E_h = mass emissions (lb/hr)

F_d = fuel factor, dry, scf/MMBtu (calculated from on-site analyzers)
C_d = CO concentration, dry basis, ppm
MW = CO molecular weight, 28 lb/mol
Q_d = volumetric flow rate, dry basis, scfm
$\%O_2$ = O_2 concentration, dry basis (from O_2 CEMS)
H_g = heat input rate (MMBtu/hr)

The resulting CO lb/hr value is then multiplied by the unit operating time for the heater for that hour to produce a CO lbs value. Hourly CO emissions (lbs) shall be summed and divided by 2000 to determine monthly CO emissions (in tons). In determining compliance with the annual emissions limitation, all periods of emissions must be included, including startups, shutdowns, emergencies and malfunctions.

Monthly emissions shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

27.2 This source is subject to the particulate matter emission limit set forth in Condition 36.1 of this permit.

27.3 This source is subject to 40 CFR Part 60 Subpart J, Standards of Performance for Petroleum Refineries as set forth in Condition 45 of this permit.

This heater combusts natural gas and PSA reject gas. The public-supplied natural gas is not a refinery fuel gas, and quantification of its sulfur content is based on annual data supplied by the public utility. PSA reject gas, generated by the hydrogen plant, is a refinery fuel gas. However, gases produced in a hydrogen plant are exempt from the sulfur monitoring requirements in NSPS Subpart J as specified in 40 CFR Part 60 §60.105(a)(4)(iv)(C).

27.4 Sulfur dioxide emissions from this source shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from this heater shall be calculated as set forth in Condition 27.1.2 of this permit.

27.5 NO_X emissions from this heater shall not exceed 0.04 lb/MMBtu, on a 3-rolling average (Colorado Construction Permit 04AD0109, as modified under the provisions on Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections II.A.7 and III.B.7 to include the NO_X emission limits in Consent Decree H-01-4430, paragraph 220(a) required for new or modified heaters associated with projects that used reductions from Consent Decree requirements for netting per paragraphs 219 and 220.) Compliance with the NO_X emission limits shall be monitored as follows:

27.5.1 **Schedule of Compliance.** In order to comply with the NO_X emission limit in Condition 27.5, the permittee shall take the following actions to install a NO_X emissions reduction device on heater H-2101:

27.5.1.1 By April 30, 2023, complete design concept (e.g., determine vendors, selective catalytic reduction (SCR) device model, capacity and other related information).

27.5.1.2 By April 30, 2025, complete detailed engineering on the project.

27.5.1.3 By January 31, 2026, complete construction planning.

27.5.1.4 By the end of the 2026 turnaround but no later than December 31, 2026, complete construction of the NO_X emissions reduction device.

Progress reports shall be submitted every six (6) months until completion of the project. (Colorado Regulation No. 3 , Part C, Section III.C.9) The first progress report shall cover the six (6) month period beginning with the issuance date of this renewal permit **July 9, 2024**. Semi-annual reports shall be submitted within 15 calendar days after the end of the six month period.

27.5.2 Upon completion of the schedule of compliance in Condition 27.5.1, compliance with the NO_X limit shall be monitored using the NO_X continuous emission monitoring system required by Condition 27.11. For every hour in which fuel is combusted in the heater, the permittee shall program the data acquisition and handling system (DAHS) to calculate the NO_X concentration in lb/MMBtu, in accordance with the requirements in 40 CFR Part 60 and Condition 59.1.1.3.b of this permit. Compliance with the NO_X emission limits in Condition 27.5 shall be based on a 3-hr rolling average. Before the end of each operating hour, the permittee must calculate and record the 3-hr rolling average emission rate in lb/MMBtu from the previous three operating hours. (An operating hour is any hour in which fuel is combusted for any time in the unit.)

27.6 Consumption of gaseous fuel in this heater shall not exceed 2,899,560,000,000 Btu (HHV) per year (Colorado Construction Permit 04AD0109). Refinery fuel gas shall be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week for refinery fuel gas and monthly for natural gas (city gas)). Monthly fuel consumption shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall calculated using the previous twelve months data.

27.7 This heater is subject to the opacity limits set forth in Conditions 35.1, 35.2 and 35.3 of this permit. Compliance with the opacity requirements shall be monitored as set forth in Condition 35.4

27.8 This heater is subject to the National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63 Subpart DDDDD as set forth in Condition 63 of this permit.

27.9 This heater is subject to RACT requirements for PM_{10}, VOC and CO (Colorado Construction Permit 04AD0109 and Colorado Regulation No. 3, Part B, Section III.D.2.a) RACT has been determined to be the following:).

27.9.1 For PM_{10} – Use of pipeline quality natural gas or PSA reject gas which meets the requirement in Condition 27.3 (40 CFR Part 60 Subpart J).

27.9.2 For CO and VOC – Use of good combustion practices. In the absence of credible evidence to the contrary, compliance with the VOC and CO RACT requirements shall be presumed provided the requirements in Conditions 27.10 (NSPS General Provisions) and 27.14 (Reg 7 combustion process adjustment requirements) are met.

27.10 This heater is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

27.11 Continuous emission monitoring systems (CEMS) shall be installed, calibrated, maintained, and operated in for the measurement of NO_X, CO, O_2 and air flow. (Colorado Construction Permit 04AD0109. Regulation No. 23, Sections V.A.1.b, V.A.1.b.(i) and V.A.1.b.(i)(D) require the use of a NO_X CEMs). The CEMs shall be operated and maintained in accordance with the requirements in Condition 59. Reports shall be submitted in accordance with the requirements in Condition 59.4 addressing monitor downtime or emissions of NO_X or CO in excess of the limitations in Conditions 27.1.3, 27.1.4 and 27.5.

27.12 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section VI.B.4).

Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.27 (Process Heater H-2101), as well as Sections II.4 (Tanks T52, T774 and T777), II.10 (Y-3 Cooling Tower), II.13 (Boilers B-6 and B-8), II.20 (TGU Incinerator H-25), II.21 (Process Heaters H-1716 and H-1717), and II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H_2 Plant Drain Systems). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants.

27.13 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, this heater is subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

Note that the exemption in Colorado Regulation No. 26, Part B, Section II.A.d.f (Condition 72.1.3) does not apply until the requirements adopted by the AQCC on December 17, 2021 into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

27.14 This heater is subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based on actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

28. Process Heater H-2410 (Rated at 51.5 MMBtu/hr)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring Method	Monitoring Interval
PM	28.1	See Condition 36.1		Fuel Restriction	Only Gaseous Fuel is Used
PM	28.2		7.45×10^{-3} lb/MMBtu	Recordkeeping Calculation	Monthly
PM_{10}					
NO_X		9.50 tons/year	0.042 lb/MMBtu		
CO		9.02 tons/year	0.04 lb/MMBtu		
VOC		1.24 tons/year	5.39×10^{-3} lb/MMBtu		
NSPS Subpart Ja	28.3	Fuel gas shall not contain H_2S in excess of: 162 ppmv, on a 3-hour rolling average, and 60 ppmv, on a 365-day rolling average		Continuous Monitoring System	Continuous
		NO_X emissions shall not exceed 40 ppmvd, corrected to 0% excess air, on a 30-day rolling average basis		Continuous Monitoring System	Continuous
SO_2	28.2	2.75 tons/year	See Condition 28.2	Recordkeeping Calculation	Monthly
	28.4	0.3 lb SO_2/bbl/day of oil processed	See Condition 28.4	Recordkeeping Calculation	Daily Monthly
Fuel Use	28.5	451,140,000,000 Btu/year		Recordkeeping	Daily Monthly
Opacity	28.6	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
		Not to exceed 20% - (**State-Only**)			
MACT	28.7	Annual Tune-Up One Time Facility Energy Assessment-		See 40 CFR Part 63 Subpart DDDDD (Condition 63)	
RACT – Reg 3	28.8	See Condition 28.8.		See Condition 28.8.	
NSPS General Provisions	28.9	General Provisions - Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Stack Height Requirement	28.10	H-2410 Stack Height shall be no less than 60.8 meters		See Condition 28.10	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Restrictions on Relaxing Emission Limitations	28.11	See Condition 28.11		Certification	Annually
RACT – Reg 7	28.12	NO_X emissions not to exceed 0.1 lb/MMBtu		See Condition 72	
	28.13	Combustion Process Adjustment Requirements		See Condition 73	

28.1 This source is subject to the particulate matter emission limits set forth in Condition 36.1 of this permit.

28.2 Emissions of air pollutants shall not exceed the limits listed in the above summary table (Colorado Construction Permit 09AD1351). **For all pollutants except SO_2**, compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above table (PM, PM_{10} and VOC from AP-42, Section 1.4, dated 7/98, Table 1.4-2, emission factors converted to lb/MMBtu by dividing by 1020 Btu/scf per footnote a, NO_X based on NSPS Ja NO_X limit (40 ppmvd at 0% O_2), converted to units of lb/MMBtu and CO from manufacturer) and the monthly fuel consumption (as required by Condition 28.5) in the following equation:

Emissions (tons/month) = [EF (lb/MMBtu) x fuel usage (MMBtu/mo)]/2000 lbs/ton

For SO_2, daily emissions shall be estimated using the daily average H_2S concentration (as determined using the continuous monitoring system required by Condition 28.3) and the daily fuel consumption (as required by Condition 58) in the following equation.

SO_2 (lbs/day) = [daily fuel flow (Mscf/day) x H_2S conc. (ppm) x 0.169 lb SO_2/ppmH_2S-1,000 Mscf]

Note that the derivation of the constant 0.169 lb SO_2/ppm H_2S-1,000 Mscf is shown in Condition 11.1.

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to determine monthly SO_2 emissions.

Monthly emissions from the heater shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

Note that PM and PM_{10} emission limits are not included in the permit for process heater H-2410 but emission from these pollutants shall be calculated and reported on revised APENs submitted for this unit.

28.3 This heater is subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

Compliance with the Subpart Ja fuel gas limits shall be monitored using a continuous H_2S monitoring system as specified in Condition 46.14. Compliance with the NSPS Ja NO_X limit shall be monitored using a NO_X continuous emission monitoring system as specified in Condition 46.18.

28.4 Sulfur dioxide emissions from this source shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from this heater shall be calculated as set forth in Condition 28.2 of this permit.

28.5 Consumption of gaseous fuel in this heater shall not exceed 451,140,000,000 Btu (HHV) per year (Colorado Construction Permit 09AD1351). Refinery fuel gas shall be monitored as set forth in Condition 58 of this permit (daily recording of fuel use for each unit, heat value (HHV) analyzed once per week). Compliance with the annual fuel use limit shall be monitored by recording the quantity of fuel consumed in the heater monthly. Monthly quantities of fuel used shall be used in the twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month rolling total shall be determined using the previous twelve months data.

28.6 This heater is subject to the opacity limits set forth in Conditions 35.1, 35.2 and 35.3 of this permit. Compliance with the opacity requirements shall be monitored as set forth in Condition 35.4.

28.7 This heater is subject to the National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63 Subpart DDDDD as set forth in Condition 63 of this permit.

28.8 This heater is subject to RACT requirements for PM_{10}, VOC, CO and NO_X (VOC and NO_X are ozone precursors). (Colorado Construction Permit 09AD1351 and Colorado Regulation No. 3, Part B, Section III.D.2.a) RACT has been determined to be the following:

28.8.1 For PM_{10} – Use of gaseous fuel.

28.8.2 For CO and VOC – Use of good combustion practices. In the absence of credible evidence to the contrary, compliance with the VOC and CO RACT requirements shall be presumed provided the requirements in Conditions 28.9 (NSPS General Provisions) and 28.13 (Reg 7 combustion process adjustment requirements) are met.

28.8.3 For NO_X – ultra low NO_X burners.

28.9 This heater is subject to the general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

28.10 The height of the reboiler stack shall be no less than 60.8 meters (Colorado Construction Permit 09AD1351, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part A, Section III to revise the stack height as indicated in the source’s December 17, 2014 submittal).

28.11 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Sections V.A.7.b and VI.B.4).

Limitations were taken on the emission units addressed as part of the GBR Unit Project to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the GBR Unit Project shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the GBR Unit Project are addressed in this Section II.28, as well Sections II.31 (F3 – GBR Unit Flare) and II.34 (F114 – GBR Unit fugitives). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

28.12 Except as provided for in Colorado Regulation No. 3, Part E, Section II.A.2, this heater is subject to the NO_X emission limit, compliance demonstration, recordkeeping and reporting requirements in Colorado Regulation No. 26, Part B, Sections II.A.4, 5, 6, 7 and 8, as set forth in Condition 72.

28.13 This heaters are subject to the combustion process adjustment requirements in Colorado Regulation No. 26, Part B, Sections II.A.6 and 7.f as set forth in Condition 73, provided that actual, uncontrolled emissions of NO_X are 5 tons per year or more, (calendar year basis). The applicability of these requirements is based actual, uncontrolled NO_X emissions for the calendar year, thus applicability can vary from year to year.

29. Plant 1 (Main Plant (MP)) Flare – F1

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
SO_2	29.1		See Condition 29.1	TRS and Flare Flow Monitor	Continuously
	29.2	<u>NSPS Subpart J Requirement:</u> Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		See Condition 29.2	
	29.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 29.3	Recordkeeping Calculation	Daily Monthly
NOx	29.1		See Condition 29.1	Recordkeeping Calculation	Annually
VOC					
CO					
PM					
PM_{10}					
RACT	29.4	See Condition 29.4		See Condition 29.4	
Heat Rate of Gases Combusted	29.5			Flow Meter Recordkeeping	Continuously, Daily
Opacity	29.6	Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Video Surveillance Camera	Continuously
NSPS General Provisions	29.7	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Hours of Operation	29.8			See Condition 29.8	
NSPS Ja Requirements	29.9	Fuel gas shall not contain H_2S in excess of 162 ppmv, on a 3-hour rolling average		Continuous H_2S Monitoring System (See Condition 46)	
		Flare Management Plan, Root Cause Analysis		See 40 CFR Part 60 Subpart Ja (Condition 46)	
MACT CC	29.10	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

29.1 For APEN reporting and fee purposes (per Colorado Regulation No. 3, Part A, Section II), annual emissions shall be calculated using the emission factors listed in the table below and the heat rate of gases combusted in the flare (as required by Condition 29.5) in the following equation:

Emissions (tons/Year) = [EF (lbs/MMBtu) x gases to flare (MMBtu/year)]/2000 (lbs/ton)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Source
PM	7.45×10^{-3}	AP-42, Section 1.4 (dated 7/98), Table 1.4-2 converted to lb/MMBtu based on a heat content of 1020 Btu/scf per footnote a
PM_{10}	7.45×10^{-3}	
CO	0.31	AP-42, Section 13.5 (dated 2/18), Table 13.5-2
NO_X	0.068	
VOC – Waste/Sweep/Purge Gas	0.2548 lb/MMBtu	Based on expected waste/sweep gas compostion, 98% control efficiency assumed.
VOC – Natural Gas (Supplemental and Pilot)	0.0395 lb/MMBtu	from Xcel gas composition data, Denver area high pressure line, December 2017, 98% control efficiency assumed

For any 15-minute block period when the Btu content of gases in the combustion zone do not meet the limit in Condition 53.91 (270 Btu/scf limit in 40 CFR Part 63 Subpart CC) or any 15-minute block period during which there was at least one minute when waste gases are routed to the flare and no pilot flame is present, VOC emissions shall be calculated assuming a control efficiency of 0%. VOC emission factors of 12.74 lb/MMBtu (waste gas) and 1.98 lb/MMBtu (natural gas) shall be used to estimate emissions during those periods.

Annual SO_2 emissions shall be estimated by summing daily SO_2 emissions, as required by Condition 29.3.

29.2 The Plant 1 Main Plant Flare is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

(As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate Consent Decree (H-01-4430) requirements that flares are subject to NSPS Subpart J. Consent Decree (H-01-4430), paragraph 156). The permittee has opted to comply with the NSPS Subpart J requirements by installing a flare gas recovery system (option c in Paragraph 156 of the Consent Decree). The following requirements apply to the operation of the flare gas recovery system:

29.2.1 Hydrocarbon Flaring Incidents and Acid Gas Flaring Incidents are subject to the Root Cause Failure Analysis and Corrective Action requirements in paragraphs 183 through 188 of the Consent Decree as set forth in Appendix G of the permit. (Consent Decree (H-01-4430), paragraphs 178 and 179)

29.2.2 Hydrocarbon Flaring Incident is defined as the continuous or intermittent flaring of refinery process gases, except for Acid Gas, Sour Water Stripper Gas, or Tail Gas that results in the emissions of SO_2 that are equal to or greater than 500 pounds in a 24-hour period. (Consent Decree (H-01-4430), paragraph 155(j))

29.2.3 Acid Gas Flaring Incident is defined as the continuous or intermittent flaring/combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of SO_2 equal to, or greater than 500 pounds in a 24-hour period. However, if 500 pounds or more of SO_2 have been emitted in a 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour periods, each period of which results in emissions equal to, or in excess of 500 pounds of SO_2, then only one Acid Gas Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of flaring within the Acid Gas Flaring Incident. (Consent Decree (H-01-4430), paragraph 155(d))

29.3 Sulfur dioxide emissions from the Plant 1 Main Plant Flare shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Conditions 38.1 of this permit. Daily SO_2 emissions from the Plant 1 Main Plant Flare shall be calculated as follows:

SO_2 emissions from flare (lb/day) = SO_2 from flared gases (lb/day) + SO_2 from natural gas (lb/day)

<u>SO_2 Emissions from pilot, flow meter purge and supplemental gases (natural gas)</u>

SO_2 (lb/day) = pilot gas flow (MMscf/day) x 1.6 lb/MMscf

SO2 (lb/day) = flow meter purge gas flow (MMscf/day) x 1.6 lb/MMscf

SO_2 (lb/day) = suppl. gas flow (MMscf/day) x 1.6 lb/MMscf

Where: pilot gas flow (MMscf/day) determined as required by Condition 29.5.1.
flow meter purge gas flow (MMscf/day) determined as required by Condition 29.5.1.
suppl. gas flow (MMscf/day) determined as required by Condition 29.5.2.
1.6 lb/MMscf = 0.55 grains S/0.1 Mscf x 1 lb S/7,000 grains S x 64 lb SO_2/32 lbs S

<u>SO_2 Emissions from flared gases (not including pilot and supplemental):</u>

Daily SO_2 emissions from flared gas will be based on the summation of the hourly SO_2 emissions measured by the total reduced sulfur (TRS) analyzer required by Condition 29.9 (NSPS Ja). Hourly SO_2 emissions are calculated from the TRS analyzer as follows:

lb SO_2/hr = FG flow (MMscf)/hr x SO_2 conc. (1-hr average ppmv) x lb-mole SO_2/385.3 scf SO_2 x 64.04 lb SO_2/lb-mole SO_2

$$\text{FG flow (MMscf/hr)} = \frac{\text{actual FG flow (MMcf/hr)} \times 527.67^{\circ}\text{ R} \times \text{P (psia)}}{(\text{T } (^{\circ}\text{F}) + 459.67) \times 14.7 \text{ psia}}$$

Where: FG flow (MMscf/hr) = flare gas flow rate at standard temperature and pressure. The flow meter required by Condition 29.5.3 is required to correct to standard temperature and pressure per 63.670(i)(1).

SO_2 conc. (ppmv) = measured total reduced sulfur (TRS) concentration in the flare gas heater, reported as SO_2 ppmv (scf SO_2/10^6 scf FG), from the TRS continuous monitoring system

actual FG flow (MMcf/hr) = actual flare gas flow rate at process temperature and pressure, as determined from flare flow meter required by Condition 29.5.3.

459.67= conversion factor converting temperature in ºF to degree Rankine.

527.67 ºR = standard temperature, in ºR, which = 68 ºF + 459.67

T = process temp, in ºF

P = process pressure, in psia

14.7 psia = standard pressure

29.4 The Plant 1 Main Plant Flare is subject to the provisions of Colorado Regulation No. 24, Part B, Section VI.B.3 and 6 as set forth in Conditions 43.2.2 and 43.2.5 of this permit.

29.5 The heat rate (Btu per year, HHV) of gases (including pilot, flow meter purge and supplemental gas) combusted in the Plant 1 Main Plant Flare shall be monitored and recorded daily as follows:

29.5.1 The quantity of pilot gas and flow meter purge gas (purchased natural gas) to the flare shall be determined based on the design rate (135 scf/hr for pilot and 240 scf/hr for flow meter purge) and daily hours of operation for the flare (as required by Condition 29.8). The Btu content of the pilot and flow meter purge gas (purchased natural gas) shall be 1020 Btu/scf (based on a net (lower) heating value (LHV) of 920 Btu/scf per 40 CFR Part 63 Subpart CC §63.670(j)(5) (Condition 53.96.3), converted to HHV by multiplying by 1.11). Daily throughput shall be summed to determine annual consumption of pilot and purge gas for use in the emission calculations required by Condition 29.1.

29.5.2 The quantity of supplemental fuel (purchased natural gas) to the flare shall be monitored using a continuous flow monitor that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(i) (see Condition 53.95). The Btu content of the supplemental fuel (purchased natural gas) shall be 1020 Btu/scf (based on a LHV of 920 Btu/scf per 40 CFR Part 63 Subpart CC §63.670(j)(5) (Condition 53.96.3), converted to HHV by multiplying by 1.11). Daily throughput shall be summed to determine annual consumption of supplemental fuel for use in the emission calculations required by Condition 29.1.

29.5.3 The quantity of process gases combusted shall be monitored using a continuous flow monitor that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(i) (see Condition 53.95). The Btu content of the process gas shall be determined using a calorimeter that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(j)(3) (see Condition 53.96.1). The calorimeter measures the Btu content in LHV, which shall be converted to HHV by multiplying by 1.14. Daily throughput shall be summed to determine annual consumption of process gases for use in the emission calculations required by Condition 29.1.

29.6 This Plant 1 Main Flare is subject to the following opacity limit: No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes. (Colorado Regulation No. 1, Section II.A.5).

In the absence of credible evidence to the contrary, compliance with above opacity limit shall be presumed provided the monitoring in Condition 53.94 indicates compliance with the visible emission requirement in Condition 53.89. In the absence of credible evidence to the contrary, for periods when the monitoring in Condition 53.94 indicates non-compliance with the visible emission requirement in Condition 53.89, the flare shall be considered out of compliance with the opacity limit in this Condition 29.6 for the entire non-compliance period, unless a Method 9 observation is conducted that indicates compliance.

29.7 The Plant 1 Main Plant Flare is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Conditions 56 of this permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirement that flares are subject to NSPS Subpart A. Consent Decree (H-01-4430), paragraph 156)

29.8 Hours of operation for the Plant 1 Main Plant Flare shall be monitored and recorded daily. Daily hours of operation shall be used to calculate daily pilot gas throughput as required by Condition 29.5.1.

29.9 The Plant 1 Main Plant Flare is subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

The flare is subject to the NSPS Ja requirements due to a modification and must comply with the requirements in NSPS Ja on November 11, 2015 or upon startup of the modified flare, whichever is later.

29.10 On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to 40 CFR Part 63 Subpart CC shall meet the applicable requirements for flares as specified in 40 CFR Part 63 Subpart CC §§63.670(a) through (q) and 63.671 (See Condition 53).

Alternatively, the owner or operator may elect to comply with the requirements of 40 CFR Part 63 Subpart CC §63.670(r) in lieu of the requirements in §63.670(d) through (f), as applicable (See Condition 53).

30. Plant 3 (Asphalt Unit (AU)) Flare – F2

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
SO_2	30.1	16.9 tons/year	See Condition 30.1	TRS and Flare Flow Monitor	Continuously
	30.2	NSPS Subpart J Requirement: Fuel gas shall not contain H_2S in excess of 0.10 gr/scf, on a 3-hour rolling average[1]		See Condition 30.2	
	30.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 30.3	Recordkeeping Calculation	Daily Monthly
VOC	30.1	8.6 tons/year	0.371 lb/MMBtu	Recordkeeping Calculation	Monthly
CO		7.2 tons/year	0.31 lb/MMBtu		
NO_X		1.6 tons/year	0.068 lb/MMBtu		
PM			7.45×10^{-3} lb/MMBtu		
PM_{10}					
$PM_{2.5}$					
RACT	30.4	See Condition 30.4			
Opacity	30.5	Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Video Surveillance Camera	Continuously
Heat Rate of Gases Combusted	30.6	46,202,974,000 Btu/year		Flow Meter Recordkeeping	Continuously Daily, Monthly
NSPS General Provisions	30.7	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Hours of Operation	30.8			Recordkeeping	Monthly
NSPS Ja	30.9	Fuel gas shall not contain H_2S in excess of 162 ppmv, on a 3-hour rolling average		H_2S Continuous Monitoring System (see Condition 46)	
		Flare Management Plan, Root Cause Analysis		See 40 CFR Part 60 Subpart Ja (Condition 46)	
MACT	30.10	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
CAM Requirements	30.11	See Condition 30.11		See Condition 30.11	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

30.1 Emissions of air pollutants shall not exceed the limits listed in the above summary table (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, based on requested emissions on the APEN submitted September 12, 2017, red-lined October 24, 2018).

For all pollutants except SO_2, compliance with the annual limitations shall be monitored by calculating monthly VOC, CO and NO_X emissions using the emission factors in the above table (NOx and CO from AP-42, Section 13.5 (dated 2/18), Table 13.5-2, VOC based on material balance (98% DRE assumed), PM, PM_{10} and $PM_{2.5}$ from AP-42, Section 1.4 (dated 7/98), Table 1.4-2, converted to lb/MMBtu by dividing by 1020 Btu/scf per footnote a) and the monthly quantity of gases combusted (including pilot gas) in the flare (as required by Condition 30.6) in the following equation:

Emissions (Tons/month) = [EF (lbs/MMBtu) x gases to flare (MMBtu/month)]/2000(lbs/ton)

For any 15-minute block period when the Btu content of gases in the combustion zone do not meet the limit in Condition 53.91 (270 Btu/scf limit in 40 CFR Part 63 Subpart CC) or any 15-minute block period during which there was at least one minute when waste gases are routed to the flare and no pilot flame is present, VOC emissions shall be calculated assuming a control efficiency of 0%. A VOC emission factor of 18.55 lb/MMBtu shall be used to estimate emissions during those periods.

For SO_2, daily emissions from the flare shall be calculated as described below.

SO_2 from the flare (lb/day) = SO_2 from flared gases (lb/day) + SO_2 emissions from pilot gas (lb/hr)

<u>SO_2 Emissions from pilot gases</u>

SO_2 (lb/day) = pilot gas flow (MMscf/day) x 1.6 lb/MMscf

Where: pilot gas (MMscf/day) = pilot gas flow determined as required by Condition 30.6.1
1.6 lb/MMscf = 0.55 grains S/0.1 Mscf x 1 lb S/7,000 grains S x 64 lb SO_2/32 lbs S

<u>SO_2 Emissions from flared gases (not including pilot):</u>

Daily SO_2 emissions from flared gas will be based on the summation of the hourly SO_2 emissions measured by the total reduced sulfur (TRS) analyzer required by Condition 30.9 (NSPS Ja). Hourly SO_2 emissions are calculated from the TRS analyzer as follows:

lb SO_2/hr = FG flow (MMscf)/hr x SO_2 conc. (1-hr average ppmv) x lb-mole SO_2/385.3 scf SO_2 x 64.04 lb SO_2/lb-mole SO_2

$$\text{FG flow (MMscf/hr)} = \frac{\text{actual FG flow (MMcf/hr)} \times 527.67\ ^{\circ}\text{R} \times \text{P (psia)}}{(\text{T } (^{\circ}\text{F}) + 459.67) \times 14.7 \text{ psia}}$$

Where: FG flow (MMscf/hr) = flare gas flow rate at standard temperature and pressure. The flow meter required by Condition 30.6.2 is required to correct to standard temperature and pressure per 63.670(i)(1).

SO_2 conc. (ppmv) = measured total reduced sulfur (TRS) concentration in the flare gas heater, reported as SO_2 ppmv (scf $SO_2/10^6$ scf FG), from the TRS continuous monitoring system

actual FG flow (MMcf/hr) = actual flare gas flow rate at process temperature and pressure, as determined from flare flow meter required by Condition 30.6.2.

459.67= conversion factor converting temperature in ºF to degree Rankine.

527.67 ºR = standard temperature, in ºR, which = 68 ºF + 459.67

T = process temp, in ºF

P = process pressure, in psia
14.7 psia = standard pressure

Daily SO_2 emissions for the month shall be calculated by the end of the subsequent month. Daily SO_2 emissions shall be summed to get monthly SO_2 emissions.

Monthly emissions shall be calculated by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be estimated using the previous twelve months data.

Note that PM and PM_{10} emission limits are not included in the permit for the Plant 3 (AU) flare but emissions from these pollutants shall be calculated and reported on revised APENs submitted for the unit.

30.2 The Plant 3 Flare is subject to 40 CFR Part 60, Subpart J, Standards of Performance for Petroleum Refineries, as set forth in Condition 45 of this permit.

(As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirement that flares are subject to NSPS Subpart J. Consent Decree (H-01-4430), paragraph 156). The permittee has opted to comply with the NSPS Subpart J requirements by installing a flare gas recovery system (option a in Paragraph 156 of the Consent Decree). The following requirements apply to the operation of the flare gas recovery system:

30.2.1 Hydrocarbon Flaring Incidents and Acid Gas Flaring Incidents are subject to the Root Cause Failure Analysis and Corrective Action requirements in paragraphs 183 through 188 of the Consent Decree as set forth in Appendix G of the permit. (Consent Decree (H-01-4430), paragraphs 178 and 179)

30.2.2 Hydrocarbon Flaring Incident is defined as the continuous or intermittent flaring of refinery process gases, except for Acid Gas, Sour Water Stripper Gas, or Tail Gas that results in the emissions of SO_2 that are equal to or greater than 500 pounds in a 24-hour period. . (Consent Decree (H-01-4430), paragraph 155(j))

30.2.3 Acid Gas Flaring Incident is defined as the continuous or intermittent flaring/combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of SO_2 equal to, or greater than 500 pounds in a 24-hour period. However, if 500 pounds or more of SO_2 have been emitted in a 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour periods, each period of which results in emissions equal to, or in excess of 500 pounds of SO_2, then only one Acid Gas Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured form the initial commencement of flaring within the Acid Gas Flaring Incident. (Consent Decree (H-01-4430), paragraph 155(d))

30.3 Sulfur dioxide emissions from the Plant 3 Flare shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from the Plant 3 (AU) flare shall be calculated as set forth in Condition 30.1 of this permit.

30.4 The Plant 3 Flare is subject to the provisions of Colorado Regulation No. 24, Part B, VI.B.3 and 6 as set forth in Conditions 43.2.2 and 43.2.5 of this permit.

30.5 The Plant 3 Flare is subject to the following opacity limit: No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes. (Colorado Regulation No. 1, Section II.A.5).

In the absence of credible evidence to the contrary, compliance with above opacity limit shall be presumed provided the monitoring in Condition 53.94 indicates compliance with the visible emission requirement in Condition 53.89. In the absence of credible evidence to the contrary, for periods when the monitoring in Condition 53.94 indicates non-compliance with the visible emission requirement in Condition 53.89, the flare shall be considered out of compliance with the opacity limit in this Condition 30.5 for the entire non-compliance period, unless a Method 9 observation is conducted that indicates compliance.

30.6 The heat rate (Btu per year, HHV) of gases (including waste, sweep, pilot and supplemental gas) sent to the Plant 3 Flare shall not exceed the limit in the above summary table. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, based on the requested throughput indicated on the APEN submitted September 12, 2017, red-lined October 24, 2018). The quantity of gases flared shall be monitored and recorded daily as follows:

30.6.1 The quantity of pilot gas to the flare shall be determined based on the design flow rate (50 scf/hr for pilot gas) and daily hours of operation for the flare (as required by Condition 30.8). The Btu content of the pilot gas (city gas) shall be based on a heat content of 1020 Btu/scf (based on a net (lower) heating value (LHV) of 920 Btu/scf per 40 CFR Part 63 Subpart CC §63.670(j)(5) (Condition 53.96.3), converted to HHV by multiplying by 1.11). Daily throughput shall be summed to determine monthly consumption of pilot gas.

30.6.2 The quantity of sweep, process and supplemental gases combusted shall be monitored using a continuous flow monitor that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(i) (see Condition 53.95). The Btu content of the sweep, supplemental and process gas shall be determined using a calorimeter that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(j)(3) (see Condition 53.96.1). The calorimeter measures the Btu content in LHV, which shall be converted to HHV by multiplying by 1.12. Daily throughput shall be summed to determine monthly consumption of sweep, process and supplemental gas.

Monthly quantities of gases flared (sweep, pilot, supplemental and process gases) shall be summed together and used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month total shall be estimated using the previous twelve months data.

30.7 The Plant 3 Flare is subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirement that flares are subject to NSPS Subpart A. Consent Decree (H-01-4430), paragraph 156)

30.8 Hours of operation for the Plant 3 Flare shall be monitored and recorded daily. Daily hours of operation shall be used to determine the monthly quantity of pilot gases combusted by the flare (as required by Condition 30.6.1).

30.9 The Plant 3 Flare is subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

The flare is subject to the NSPS Ja requirements due to a modification and must comply with the requirements in NSPS Ja on November 11, 2015 or upon startup of the modified flare, whichever is later.

30.10 On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to 40 CFR Part 63 Subpart CC shall meet the applicable requirements for flares as specified in 40 CFR Part 63 Subpart CC §§63.670(a) through (q) and 63.671 (See Condition 53).

Alternatively, the owner or operator may elect to comply with the requirements of 40 CFR Part 63 Subpart CC §63.670(r) in lieu of the requirements in §63.670(d) through (f), as applicable (See Condition 53).

30.11 The Plant 3 flare is subject to the compliance assurance monitoring (CAM) requirements with respect to the VOC emission limitation identified in Condition 30.1. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plan in Appendix N.

31. GBR Unit Flare – F3

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
NOx	31.1	14.2 tons/year	0.068 lb/MMBtu	Recordkeeping Calculation	Monthly
VOC		27.1 tons/year	See Condition 31.1.2		
CO		60.5 tons/year	See Condition 31.1.2		
PM			7.45×10^{-3} lb/MMBtu		
PM_{10}					
$PM_{2.5}$					
NSPS Subpart Ja	31.2	Fuel gas shall not contain H_2S in excess of 162 ppmv, on a 3-hour rolling average		Fuel Gas Streams Inherently Low in Sulfur	
		Flare Management Plan, Root Cause Analysis		See 40 CFR Part 60 Subpart Ja (Condition 46)	
SO_2	31.3	0.3 lb SO_2/bbl/day of oil processed	See Condition 31.3	Recordkeeping Calculation	Daily Monthly
RACT	31.4	See Condition 31.4			
Opacity	31.5	Not to exceed 30% for a period or periods aggregating more than six minutes in any sixty consecutive minutes		Video Surveillance Camera	Continuously
Heat Rate of Gases Combusted	31.6	Waste/Sweep Gas: 180,500,000,000 Btu/year Natural Gas: 236,069,389,000 Btu/year		Recordkeeping	Monthly
NSPS General Provisions	31.7	General Provisions – Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
Stack Height Requirement	31.8	GBR flare height shall be no less than 75.9 meters		See Condition 31.8	
MACT	31.9	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Restrictions on Relaxing Emission Limitations	31.11	See Condition 31.11		Certification	Annually
CAM Requirements	31.12	See Condition 31.12		See Condition 31.12	

31.1 Emissions of air pollutants shall not exceed the limits listed in the above summary table (Colorado Construction Permit 10A1768, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, based on requested emissions on the APEN submitted November 1, 2019). Compliance with the emission limitations shall be monitored as follows:

31.1.1 **For PM, PM_{10}, $PM_{2.5}$ and NO_X** emissions, compliance with the annual limitations shall be monitored by calculating monthly emissions using the emission factors in the above summary table (NO_X, from AP-42, Section 13.5 (dated 2/18), Table 13.5-1 and PM, PM10 and PM2.5 from AP-42, Section 1.4 (dated 7/98), converted to lb/MMBtu by dividing by 1020 Btu/scf per footnote a) and the monthly quantity of gases combusted (waste/sweep gas and natural gas) in the flare (as required by Condition 31.6) in the following equation:

Emissions (tons/month) = [EF (lbs/MMBtu) x total gases combusted (MMBtu/month)]/2000 (lbs/ton)

Where: Total gases combusted = waste/sweep gas (MMBtu/mo) + natural gas (MMBtu/mo)

Monthly emissions shall be calculated by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be estimated using the previous twelve months data.

Note that PM, PM_{10} and $PM_{2.5}$ emissions limits are not included in the permit but emissions from these pollutants shall be calculated and reported on revised APENS.

31.1.2 **For VOC and CO** emissions, compliance with the annual limitation shall be monitored by calculating emissions monthly using the monthly quantities of sweep/waste gas and natural gas consumed (as required by Condition 31.6) and the emission factors in table below in the following equations:

VOC or CO emissions (ton/mo) = emissions from waste/sweep gas combustion + emissions from natural gas consumption

Emissions from waste/sweep gas combustion = waste/sweep gas consumed (MMBtu/mo) x EF (lb/MMBtu)/2000 lb/ton

Emissions from natural gas combustion = natural gas consumed (MMBtu/mo) x EF (lb/MMBtu) x EF (lb/MMBtu)/2000 lb/ton

	Emission Factor	Emission Factor Source
CO – Waste/Sweep Gas	0.2646 lb/MMBtu	AP-42, Section 13.5 (dated 2/18), Table 13.5-2, adjusted for expected H_2 concentration in waste/sweep gas.
CO – Natural Gas	0.31 lb/MMBtu	AP-42, Section 13.5 (dated 2/18), Table 13.5-2
VOC – Waste/Sweep Gas	0.2482 lb/MMBtu	Based on expected waste/sweep gas compostion, 98% control efficiency assumed.
VOC – Natural Gas	0.0395 lb/MMBtu	from Xcel gas composition data, Denver area high pressure line, December 2017, 98% control efficiency assumed

For any 15-minute block period when the Btu content of gases in the combustion zone do not meet the limit in Condition 53.91 (270 Btu/scf limit in 40 CFR Part 63 Subpart

CC) or any 15-minute block period during which there was at least one minute when waste gases are routed to the flare and no pilot flame is present, VOC emissions shall be calculated assuming a control efficiency of 0%. A VOC emission factors of 12.41 lb/MMBtu (waste gas) and 1.98 lb/MMBtu (natural gas) shall be used to estimate emissions during those periods.

Monthly emissions shall be calculated by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual emission limitations. Each month a new twelve month total shall be estimated using the previous twelve months data.

31.2 The GBR Flare is subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

Note that the flare is exempt from the H_2S monitoring requirements as specified in Conditions 46.15 and 46.19.4 although other requirements in Subpart Ja, such as developing and implementing a flare management plan and conducting root cause analyses are applicable to the flare.

31.3 Sulfur dioxide emissions from the GBR Flare shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limits set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emission limit, daily SO_2 emissions from the GBR flare shall be calculated as set forth as follows:

SO_2 emissions from flare (lb/day) = SO_2 from waste/sweep gas (lb/day) + SO_2 from natural gas (lb/day)

<u>SO_2 from natural gas (pilot and supplemental)</u>

SO_2 (lb/day) = pilot gas flow (Mscf/day) x 1.6 lb/MMscf

SO2 (lb/day) = flow meter purge gas flow (Mscf/day) x 1.6 lb/MMscf

SO_2 (lb/day) = suppl. gas flow (Mscf/day) x 1.6 lb/MMscf

Where: pilot gas flow (Mscf/day) determined as required by Condition 31.6.2.2.
flow meter purge gas flow (Mscf/day) determined as required by Condition 31.6.2.2.
suppl. gas flow (Mscf/day) determined as required by Condition 31.6.2.1.
1.6 lb/MMscf = 0.55 grains S/0.1 Mscf x 1 lb S/7,000 grains S x 64 lb SO_2/32 lbs S

<u>SO2 from waste/sweep gas</u>

Daily SO2 emissions from flared gas will be based on the summation of the hourly SO2 emissions measured by the total reduced sulfur (TRS) analyzer required by Condition 31.2 (NSPS Ja). Hourly SO2 emissions are calculated from the TRS analyzer as follows:

lb SO2/hr = FG flow (Mscf)/hr x 1,000 scf/Mscf FG x SO2 conc. (1-hr average ppmv) x lb-mole SO2/385.3 scf SO2 x 64.04 lb SO2/lb-mole SO2

$$\text{FG flow (Mscf/hr)} = \frac{\text{actual FG flow (Mcf/hr) x 527.67 °R x P (psia)}}{\text{(T (°F) + 459.67) x 14.7 psia}}$$

Where: FG flow (Mscf/hr) = flare gas flow rate at standard temperature and pressure. The flow meter required by Condition 31.6.1 is required to correct to standard temperature and pressure per 63.670(i)(1).

SO2 conc. (ppmv) = measured total reduced sulfur (TRS) concentration in the flare gas heater, reported as SO2 ppmv (scf SO2/106 scf FG), from the TRS continuous monitoring system

actual FG flow (Mcf/hr) = actual flare gas flow rate at process temperature and pressure, as determined from flare flow meter required by Condition 31.6.1.

459.67= conversion factor converting temperature in ºF to degree Rankine.

527.67 ºR = standard temperature, in ºR, which = 68 ºF + 459.67

T = process temp, in ºF

P = process pressure, in psia

14.7 psia = standard pressure

31.4 The GBR Flare is subject to RACT requirements for PM_{10}, VOC, CO and NO_X (VOC and NO_X are ozone precursors). (Colorado Construction Permit 10AD1768, as modified under the provisions of Section I, Condition 1.3 to include PM_{10} and to indicate RACT for VOC is met by meeting the requirements in Colorado Regulation No. 24, Part B, Section VI.B.3 and 6 and Colorado Regulation No. 3, Part B, Section III.D.2.a) RACT has been determined to be the following:

31.4.1 For VOC the requirements in Colorado Regulation No. 24, Part B, Section VI.B.3 and 6 as set forth in Conditions 43.2.2 and 43.2.5 are RACT.

31.4.2 For NO_X, CO and PM_{10} RACT is satisfied by operating the flare in accordance with the flare requirements in Condition 31.9.

31.5 The GBR flare is subject to the following opacity limit: No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes. (Colorado Regulation No. 1, Section II.A.5).

In the absence of credible evidence to the contrary, compliance with above opacity limit shall be presumed provided the monitoring in Condition 53.94 indicates compliance with the visible emission requirement in Condition 53.89. In the absence of credible evidence to the contrary, for periods when the monitoring in Condition 53.94 indicates non-compliance with the visible emission requirement in Condition 53.89, the flare shall be considered out of compliance with the opacity limit in this Condition 31.5 for the entire non-compliance period, unless a Method 9 observation is conducted that indicates compliance.

31.6 The quantity of gases combusted by the GBR flare shall not exceed the following limitations:

31.6.1 Consumption of waste/sweep gas by the flare shall not exceed 180,500,000,000 Btu per year (Colorado Construction Permit 10AD1768, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, based on requested emissions on the APEN submitted November 1, 2019). Compliance with the waste/sweep gas limit shall be monitored by recording the quantity of waste/sweep gas sent to the flare daily using a continuous flow monitor that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(i) (see Condition

53.95). The Btu content of the process gas shall be determined using a calorimeter that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(j)(3) (see Condition 53.96.1). The calorimeter measures the Btu content in LHV, which shall be converted to HHV by multiplying by 1.13. Daily throughput shall be summed to determine monthly consumption of waste/sweep gases. The monthly heat rate (HHV) of waste/sweep gas combusted by the flare shall be used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

31.6.2 Consumption of purchased natural gas (supplemental, pilot and flow meter purge gas) by the flare shall not exceed 236,069,389,000 Btu per year (Colorado Construction Permit 10AD1768, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, based on requested emissions on the APEN submitted November 1, 2019). The quantity of purchased natural gas consumed by the flare shall be monitored and recorded daily as follows:

31.6.2.1 The quantity of supplemental fuel (purchased natural gas) shall be monitored using a continuous flow monitor that meets the requirements in 40 CFR Part 63 Subpart CC § 63.670(i) (see Condition 53.95). The Btu content of the supplemental fuel (purchased natural gas) shall be 1020 Btu/scf (based on a LHV of 920 Btu/scf per 40 CFR Part 63 Subpart CC §63.670(j)(5) (Condition 53.96.3), converted to HHV by multiplying by 1.11). Daily throughput shall be summed to determine monthly consumption of supplemental fuel.

31.6.2.2 The quantity of pilot and flow meter purge gas (purchased natural gas) shall be determined based on the design rate (186 scf/hr for pilot and 240 scf/hr for flow meter purge) and daily hours of operation for the flare (as required by Condition 31.10. The Btu content of the pilot and flow meter purge gas (purchased natural gas) shall be 1020 Btu/scf (based on a LHV of 920 Btu/scf per 40 CFR Part 63 Subpart CC §63.670(j)(5) (Condition 53.96.3), converted to HHV by multiplying by 1.11). Daily throughput of pilot and flow meter purge gas shall be summed to determine monthly consumption of pilot and flow meter purge gas.

Monthly quantities of purchased natural gas shall be summed together and used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month total shall be estimated using the previous twelve months data.

31.7 This flare is subject to the general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

31.8 The height of the flare shall be no less than 75.9 meters (Colorado Construction Permit 10AD1768, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part A, Section III to revise the stack height as indicated in the source's December 17, 2014 submittal).

31.9 On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to 40 CFR Part 63 Subpart CC shall meet the applicable requirements for flares as specified in 40 CFR Part 63 Subpart CC §§63.670(a) through (q) and 63.671 (See Condition 53).

Alternatively, the owner or operator may elect to comply with the requirements of 40 CFR Part 63 Subpart CC §63.670(r) in lieu of the requirements in §63.670(d) through (f), as applicable (See Condition 53).

31.10 Hours of operation shall be monitored and recorded daily. Daily hours of operation shall be used to calculate the daily pilot and flow meter purge gas as required by Condition 31.6.2.2.

31.11 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Sections V.A.7.b and VI.B.4).

Limitations were taken on the emission units addressed as part of the GBR Unit Project to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the GBR Unit Project shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the GBR Unit Project are addressed in this Section II.31, as well Sections II.28 (Process Heater H-2410) and II.34 (F114 – GBR Unit fugitives). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

31.12 The GBR Flare is subject to the compliance assurance monitoring (CAM) requirements with respect to the VOC emission limitation identified in Condition 31.1. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plan in Appendix N.

32. Asphalt Unit (Plant 3) Wastewater Treatment System – F101 - CPI Separator

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	32.1	Plant 3 Wastewater Treatment System (CPI Separator and drains): 5.44 tons/year	CPI Separator: ToxChem Model Drains: See Condition 32.1	Recordkeeping Calculation	Annually
NSPS	32.2	See 40 CFR Part 60 Subpart QQQ (Condition 51) oil-water separator requirements		Inspection	Semi-Annually
Wastewater/Oil Separators RACT	32.3	Wastewater/Oil Separators		Inspection	Semi-Annually
MACT	32.4	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Separator Requirements	32.5	Separator shall be completely enclosed and vapors vented through a carbon filter		See Condition 32.5	
Throughput	32.6			Recordkeeping	Monthly
NSPS General Provisions	32.7	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	

32.1 VOC emissions from the Plant 3 wastewater treatment system (CPI separator and drains) shall not exceed the limit listed in the above summary table (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase emissions as requested on the APEN submitted October 23, 2014, red-lined February 10, 2015). Compliance with the annual limitation shall be monitored by calculating emissions as follows:

32.1.1 Emissions from the CPI separator shall be calculated annually using ToxChem version 4.3 (or most recent version). In addition, a review of the ToxChem model shall be conducted annually to determine if updates to the model are necessary. The review should address the addition and/or removal of components and changes in flows and/or concentration levels. Changes to the previous version of the model shall be documented, maintained and made available to the Division upon request.

32.1.2 Emissions from the drain system shall be calculated annually using the emission factors included in the table below:

Equipment Type[1]	Emission Factor (lb/unit/hr)	Emission Factor Source
Junction Boxes	0.0704	EPA-450/3-85-001a, "VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards," dated February 1985, page 3-27.
Controlled Drains	3.2×10^{-3}	AP-42, Section 5.1 (dated 1/95), Table 5.1-4. 95% control efficiency presumed, based on EPA's March 2011 spreadsheet that supports EPA's emission estimation protocol for petroleum refineries (see https://www.epa.gov/air-emissions-factors-and-quantification/emissions-estimation-protocol-petroleum-refineries).
Capped Drains[2]	3.2×10^{-3}	

[1]Permitted emissions are based on 58 controlled drains, 15 junction boxes and 40 capped drains.
[2]Capped drains are equipped with water seals. Emissions from capped drains shall be based on the hours per year that the drains are open.

32.2 The CPI separator is subject to 40 CFR Part 60, Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems, as set forth in Condition 51 of this permit.

32.3 The CPI separator is subject to Colorado Regulation No. 24, Part B, VI.A.2 as set forth in Condition 43.1 of this permit.

32.4 The CPI separator is subject to the requirements or 40 CFR Part 63 Subpart CC as set forth in Condition 53 of this permit.

32.5 The separator shall be completely enclosed and vapors vented through a carbon filter. (Colorado Construction Permit 91AD726R) The permittee shall monitor for breakthrough from the carbon filter, at times when there is actual flow to the filter, at a frequency of no greater than once every 14 days. "Breakthrough" shall be defined as any reading equal to or greater than 500 ppm VOC at the outlet of the carbon filter. The permittee shall replace the carbon filter within 24 hours of detecting breakthrough.

32.6 Records of the annual quantities of water treated and water processed through the separators shall be maintained and made available to the Division upon request.

32.7 The CPI separator is subject to the general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

33. Fugitive VOC Equipment Leaks without Permitted Emission Limits – F107

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	33.1		Guideware	Recordkeeping Calculation	Annually
Equipment Leaks: MACT Requirements	33.2	Inspection and Repair Requirements – 40 CFR Part 63 Subpart CC		Inspection	See 40 CFR Part 63 Subpart CC (Condition 53)
RACT Requirements	33.3	See Condition 33.3		See Condition 33.3	
NSPS Requirements (Components/ Component Groupings Meeting the Applicability Requirements)	33.4	General Provisions - Subpart A (Condition 56		See 40 CFR Part 60 Subparts A (Condition 56), and GGGa (Condition 47)	
		Specific Requirements – Subpart GGGa (Condition 47)			

33.1 For APEN reporting and fee purposes, VOC emissions from equipment leaks associated with components not subject to permitted emission limitations shall be estimated annually using Guideware. Guideware is Suncor's tracking software program for fugitive VOC emissions from components which estimates emissions based on EPA's "Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995. Guideware estimates emissions based on actual leak data for those components that are screened and emission factors and assumed control efficiencies for those components that are not screened. Total VOC emissions for purposes of APEN reporting and fee purposes shall be the sum of VOC emissions from each component type.

33.2 Equipment leaks associated with these sources are subject to the requirements of 40 CFR Part 63 Subpart CC as set forth in Condition 53 of this permit.

Note that equipment leaks that are subject to requirements in 40 CFR Part 63 Subpart GGGa are only required to comply with the requirements in Subpart GGGa, except that pressure relief devices in organic service must only comply with the requirements in 63.648(j) (Condition 53.49) per 63.640(p)(2) (Condition 53.43.2).

33.3 Equipment leaks associated with these sources are subject to the requirements in Colorado Regulation No. 24, Part B, Section VI.C as set forth in Condition 43.3 of this permit.

33.4 Equipment leaks associated with components and component groupings meeting the applicability requirements in 40 CFR Part 60 Subpart GGGa §60.590a are subject to the following requirements:

33.4.1 These sources are subject to the NSPS general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

33.4.2 Those sources meeting the applicability requirements in §60.590a are subject to the requirements in 40 CFR Part 60, Subpart GGGa, Standards of Performance for Equipment Leaks in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 as set forth in Condition 47 of this permit.

The permittee shall retain records of components not subject to permit limits that meet the applicability requirements in 40 CFR Part 60 Subpart GGGa. Such records shall be made available to the Division upon request.

34. Fugitive VOC Equipment Leaks with Permitted Emission Limits

Asphalt Unit (Plant 3) Wastewater Treatment System – Individual Drain Systems – F101

Asphalt Processing Unit Fugitives – F102

Number 3 Hydrodesulfurizer Fugitives – F103

Cryogenic Vapor Recovery Unit Fugitives – F104

Number 2 Hydrodesulfurizer Fugitives – F105

Light Straight Run Distillation Tower Fugitives – F106

Vapor Recovery Unit Debutanizer Fugitives – F108

Number 4 Hydrodesulfurizer Fugitives – F109

Tail Gas Unit Amine Treatment System Fugitives – F110

Sour Water Stripper System Fugitives – F111

Modified Tank Farm Piping Fugitives – F112

Catalytic Reforming Unit Modification Fugitives – F113

GBR Unit Fugitives – F114

Bio-Diesel Fugitives – F115

Relief Valve Project – F116

Pipeline Receipt Station Fugitives – F200

MPV Project Fugitives – F202

H_2 Plant Individual Drain Systems – F204

Plant 1 Rail Rack RSR Compliance Project – F205

No. 2 HDS Tier 3 ULSG Project Fugitives – F206

Boiler B-4 Fuel Gas Filter-Coalescer Fugitives – F207

P1 Main Plant Flare Isolation Valve Project – F208

Reformulated Gasoline (RFG) Project – F209

P3 Flare RSR Project Fugitives – F210

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC*	34.1	F102: 9.13 tons/year F103: 23.82 tons/year F104: 10.06 tons/year F105: 1.81 tons/year F106: 4.5 tons/year F108: 6.8 tons/year F109: 9.68 tons/year F110: 1.27 tons/year F111: 0.12 tons/year F112: 5.27 tons/year F113: 4.5 tons/year F114: 9.24 tons/year F115: 3.38 tons/year F116: 3.61 tons/year F200: 1.84 tons/year F202: 3.71 tons/year F204: 5.2 tons.year F205 – 2.13 tons/year F206: 1.14 tons/year F207: 2.66 tons/year F208: 1.14 tons/year F209: 0.81 tons/year F210: 0.11 tons/year	All but F204 – Guideware F204 – 0.064 lb/hr/drain	Recordkeeping Calculation	Annually
Equipment Leaks: NSPS and MACT Requirements	34.2	Inspection and Repair Requirements All but F101 and F204: 40 CFR Part 60 Subpart GGGa		Inspection	See 40 CFR Part 60 Subpart GGGa (Condition 47)
F106 and F116: Flaring of Relief Valves	34.3	Relief Valves shall be routed to a flare.			
F108: Wastewater Drains	34.4			Inspection	See 40 CFR Part 60 Subpart QQQ (Condition 51)
F109 and F111: Equipment Leaks	34.5	Inspection and Repair Requirements		Inspection	Quarterly
F101, F103, F104, F109, F110, F113, F114 and F204: Wastewater NSPS Requirements	34.6	Drain Requirements		See 40 CFR Part 60 Subpart QQQ (Conditions 51.3 thru 51.16)	
RACT Requirements – Equipment Leaks and Drains	34.7	See Condition 34.7		See Condition 34.7	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
NSPS General Provisions	34.8	See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
F101: Inactive Component Requirements	34.9	See Condition 34.9		See Condition 34.9	
F102, F103, F105, F108, F109, F110, F111, F112, F114 & F204: Restrictions on Relaxing Emission Limitations	34.10	See Condition 34.10		Certification	Annually
F206 Pump Requirements	34.11	High-Speed Ethanol Unloading Pump (08-P-668) Shall be Equipped with Dual Mechanical Seals with a Pressurized Barrier Fluie		See Condition 34.11	

*The Asphalt unit (Plant 3) wastewater treatment system is subject to an overall VOC limits, which includes the CPI separator and drain systems. This limit is included in Condition 32.1 of this permit.

34.1 Emissions of air pollutants shall not exceed the limitations listed in the above summary table. (Colorado Construction Permits 89AD164 (F104), 91AD180-2 (F102), as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to increase emission limit as specified in the APEN submitted on 12/22/10**,** 91AD180-1 (F103), 91AD180-4 (F105), 85AD079 (F106), 01AD0363 (F108), 04AD0110 (F109), 04AD0111 (F110), 04AD0112 (F111), 04AD0113 (F112), revised under the provisions in Section I, Condition 1.3 to remove the number of components specified in the various construction permits, 09AD1352 (F114), 20AD0715 (F210), and for F113, F115, F116, F200, F202, F204, 205, 206, 207, 208 209 and 210, as provided for under the provisions in Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to set emission limits as specified in the APENs submitted on November 15, 2011 (F113), January 30, 2012 (F115), April 29, 2015 (F116), July 11, 2016, red-lined December 30. 2016 (F200), February 10, 2017 (F202), November 15, 2017 (F204), June 14, 2018 (F205), November 5, 2018 (F206), September 12, 2017, red-lined February 16, 2018 (F207), September 25, 2018, red-lined December 17, 2020 (F208), January 19, 2022 (F209), and September 12, 2017, red-lined February 6, 2018 (F210)) Compliance with the emission limitations shall be monitored as follows:

34.1.1 **For all but F204:** VOC emissions shall be calculated annually for each emission group (e.g. modified tank farm), using Guideware. Guideware is Suncor's fugitive emission's tracking software program which estimates emissions based on EPA's "Protocol for Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995. Guideware estimates emissions based on actual leak data for those components that are screened and emission factors and assumed control efficiencies for those components that are not screened.

34.1.2 **For F204:** VOC emissions shall be calculated monthly using the number of hours in the month and the emission factor in the above summary table (from AP-42, Section 5.1 (dated 4/15), Table 5.1-4) in the equation below:

VOC (ton/mo) = [EF (lb/drain-hr) x No. of Drains x No. of hours in the month]/2000 lb/ton

Note that the control efficiencies listed in the table below can be applied to the above calculations provided the requirements in Condition 34.6 have been met for the controlled drains.

Control[1]	Control Efficiency	Source
Water seals	50%	EPA-450/3-85-001a, February 1985, "VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards", page 4-9
Gasketed and Sealed Lids	23%	EPA-450/3-85-001b, December 1987, "VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Promulgated Standards", page 2-23

[1]Permitted emissions include 35 drains. 25 drains and 6 catch basins are equipped with water seals and 1 manhole and 3 clean-outs are equipped with gasketed and sealed lids.

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve-month rolling total to monitor compliance with the annual limitation. Each month a new twelve month total shall be calculated using the previous twelve months data.

34.2 Except as provided for in Condition 34.2.1, equipment leaks associated with these sources, **except for F101 and F204**, are subject to the requirements of 40 CFR Part 63 Subpart CC as set forth in Condition 53 of this permit.

34.2.1 Components and component groupings that are subject to the requirements in 40 CFR Part 6 Subpart GGa are only required to comply with the requirements in Subpart GGa, except that pressure relief devices in organic service must only comply with the requirements in 63.648(j) (Condition 53.49) per 63.640(p)(2) (Condition 53.43.2).

All component groupings **except for F101 and F204** are subject to the requirements of 40 CFR Part 60 Subpart GGGa as set forth in Condition 47 of this permit.

34.3 The following relief valves shall be vented to a flare:

34.3.1 The two (2) relief valves for F106 shall be vented to a flare. (Colorado Construction Permit 85AD079)

34.3.2 The twenty five (25) relief valves for F116 shall be vented to a flare. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, requested emissions are based on these valves being routed to a flare)

34.4 The F108 wastewater drains shall be included in the facility's New Source Performance Standard Subpart QQQ drain inspection program. (Note: The wastewater drains are not subject to Subpart QQQ, however, the permittee will include the drains in the inspection program in order to use the control efficiency associated with Subpart QQQ inspections, for emission estimation purposes.) (Colorado Construction Permit 01AD0363)

34.5 Equipment leaks for F109 and F111 are defined as 500 ppm for valves in light liquid and/or gaseous service, excluding pressure relief devices and 2,000 ppm for pumps in light liquid and/or gas service. Valves and pumps shall be monitored for leaks quarterly using the method specified in Condition 43.3.5. The monitoring frequency shall be quarterly. The first attempt at repair shall be conducted whenever a leak, as defined in this condition, is detected. (Colorado Construction Permits 04AD0110 and 04AD0112, as modified under the provisions in Section I, Condition 1.3 to specify the monitoring method)

34.6 The individual drain systems associated with F101, F103, F104, F109, F110, F113, F114 and F204 are subject to the requirements in 40 CFR Part 60 Subpart QQQ, Standards of Performance for VOC emissions from Petroleum Refinery Wastewater Systems, specifically the requirements in §60.692-2, as set forth in Conditions 51.3 through 51.16 of this permit.

34.7 Equipment leaks and drains associated with these sources are subject to the requirements in Colorado Regulation No. 24, Part B, Section VI.C as set forth in Condition 43.3 of this permit.

34.8 These sources are subject to the general provisions in 40 CFR Part 60 Subpart A as set forth in Condition 56 of this permit.

34.9 For F101: Inactive drains shall be completely sealed, the seal shall not be removed more than 1 hour per week. All drains and junction boxes shall be equipped with water seals. (Colorado Construction Permit 91AD726R, revised in accordance with Section I, Condition 1.3 of this permit)

34.10 The requirements of Colorado Regulation No. 3, Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Sections V.A.7.b and VI.B.4). These provisions apply to the following projects:

34.10.1 **GBR Unit Project (F114):** Limitations were taken on the emission units addressed as part of the GBR Unit Project to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the GBR Unit Project shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the GBR Unit Project are addressed in this Section II.34, as well Sections II.31 (F3 – GBR Unit Flare) and II.28 (Process Heater H-2410). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

34.10.2 **Clean Fuels Project (F102, F103, F105, F108, F109, F110, F111, F112 and F204):** Limitations were taken on the emission units addressed as part of the Clean Fuels Project (CFP) to keep emissions below the significance levels. Therefore, modifications to increase the emission limitations for the emission units addressed as part of the CFP shall be re-assessed as a whole to determine if the emissions increase exceeds the significance level. The emission units associated with the CFP are addressed in this Section II.34 (F102 – Asphalt Unit Fugitives, F103 – No. 3 HDS Fugitives, F105 - No. 2 HDS Fugitives, F108 – Debutanizer Fugitives, F109 – No. 4 HDS Fugitives, F110 – Amine System Fugitives, F111 - SWS System Fugitives, F112 – Tank Farm Fugitives and F204 H_2 Plant Drain Systems), as well as Sections II.4 (Tanks T52, T774 and T777), II.10 (Y-3 Cooling Tower), II.13 (Boilers B-6 and B-8), II.20 (TGU Incinerator H-25), II.21 (Process Heaters H-1716 and H-1717), and II.27 (Process Heater H-2101). The assessment of emission increases for issuance of the initial construction permit and subsequent modifications to that equipment is included in Appendix L of this permit.

It should be noted that at the time the CFP was permitted (application received January 29, 2004, permits issued May 24, 2004), the area in which the facility was located was designated as attainment or attainment maintenance for all pollutants, thus only the requirements in Regulation No. 3, Part D, Section VI.B.4 apply.

34.11 For **F209**, the high-speed ethanol unloading pump shall be equipped with dual mechanical seals with a pressurized barrier fluid system and must meet the requirements in 40 CFR Part 60 Subpart VVa § 60.482-2a(d) (Condition 55.14), F209 is subject to the requirements in 40 CFR Part 60 Subpart GGGa (as noted in Condition 34.2.1) which requires sources to meet the requirements in 40 CFR Part 60 Subpart VVa §§ 60.482–1a to 60.482–10a.

35. Opacity Limits

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Opacity	35.1	Not to exceed 20%, except as provided for in 35.2, below		Based on emission unit type. See Conditions 35.4 thru 35.8.	
	35.2	Special Conditions - Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
Opacity- **state-only**	35.3	Not to exceed 20%		Based on emission unit type. See Conditions 35.4 thru 35.8.	

35.1 Except as provided in Condition 35.2 below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20 percent opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement on which the standards in Regulation No. 1 Section II.A are based is EPA Method 9 (40 CFR, Part 60, Appendix A (July, 1992)). (Colorado Regulation No. 1, II.A.1)

35.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere of any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30 percent opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

35.3 **State-only Requirement:** No owner or operator subject to the provisions of this regulation may discharge, or cause the discharge into the atmosphere of any particulate matter which is greater than 20% opacity. (Colorado Regulation No. 6, Part B, II.C.3 and VII.C – These are **State-Only** requirements. The provisions in Section VII.C only apply to the TGU incinerator (H-25))

This opacity standard applies at all times except during periods of startup, shutdown, or malfunction. (40 CFR Part 60, Subpart A, 60.11 (c), as adopted by reference in Colorado Regulation No. 6, Part B, I.A).

Compliance with the above opacity standards shall be monitored as follows:

35.4 **Fuel Burning Equipment**

35.4.1 For all fuel burning equipment, in the absence of credible evidence to the contrary, compliance with the opacity limits in Conditions 35.1, 35.2 and 35.3 shall be presumed since only gaseous fuel is permitted to be used as fuel. The permittee shall maintain records to verify that only gaseous fuel is used.

35.5 **Sulfur Recovery Units with Tail Gas Unit and Incinerator**

Compliance with the opacity limitations in Conditions 35.1, 35.2 and 35.3 shall be monitored as follows:

35.5.1 The permittee shall perform a visual inspection of the source stack (H-25) at least once per month. Such inspection shall last at least six minutes. Unless prior written approval is received by the Division, monthly visible inspections shall be separated by at least one (1) week. When visible emissions persist for more than six (6) minutes, an EPA Reference Method 9 observation shall be performed within one-half hour. The EPA Method 9 observations conducted to satisfy the requirements in Condition 35.5.2 shall also satisfy the requirement to conduct a visible emission observation for that month.

35.5.2 The permittee shall conduct an EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) quarterly.

35.5.3 Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

35.5.4 All opacity observations shall be performed by an observer with current and valid Method 9 certification. Results of Method 9 readings and a copy of the certified Method 9 reader's certificate shall be kept on site and made available to the Division upon request.

35.6 **FCCU**

35.6.1 For the FCCU Regenerator Vent: Compliance with the opacity limits in Conditions 35.1 and 35.2 will be monitored by means of the COM required by Condition 45.4.1.

35.6.2 For FCCU Catalyst Buildup Removal: Removal of catalyst buildup from the internal surfaces of the Waste Heat Boiler is considered to be "soot blowing" for opacity limit purposes and subject to the opacity limitation in Condition 35.2. The permittee shall follow the Division approved plan as set forth in Appendix J of this permit for determining when the 30% limit applies and how compliance will be monitored.

35.6.3 For FCCU Catalyst Loading/Unloading: Compliance with the opacity limits in Conditions 35.1 and 35.2 shall be monitored as follows:

35.6.3.1 Established standard operating procedures (SOPs) minimizing visible emissions shall be followed when loading and unloading FCCU catalyst. These SOPs shall be in written form and made available to the Division for inspection upon request.

35.6.3.2 Quarterly EPA Reference Method 9 opacity readings shall be conducted while the loading/unloading activity is taking place. Unless prior written approval is received by the Division, quarterly opacity observations shall be separated by at least one (1) month.

35.6.3.3 Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

35.6.3.4 All opacity observations shall be performed by an observer with current and valid Method 9 certification. Results of Method 9 readings and a copy of the certified Method 9 reader's certificate shall be kept on site and made available to the Division upon request.

35.6.3.5 If FCCU catalyst loading and/or unloading does not take place within the semi-annual period, then no Method 9 opacity readings are required for that semi-annual period.

35.6.3.6 Records of the date and time of each loading/unloading activity shall be maintained on site for Division inspection upon request.

35.7 **Rail Loading Rack Enclosed Vapor Combustion Unit (R101)**

35.7.1 Visible emission observations shall be conducted daily when materials are being loaded. Such visible emissions checks shall last a minimum of six (6) minutes. If no visible emissions are present, then in the absence of credible evidence to the contrary the combustor shall be presumed to be in compliance with the opacity requirements.

35.7.2 If visible emissions are observed, then a Method 9 opacity observation shall be conducted in order to assess compliance with the opacity limitations.

35.7.3 Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

35.7.4 All opacity observations shall be performed by an observer with current and valid Method 9 certification. Results of Method 9 readings and a copy of the certified Method 9 reader's certificate shall be kept on site and made available to the Division upon request.

35.7.5 Daily visible emission observations are not required on days when no materials are loaded.

35.8 **Reformer**

35.8.1 For Reformer Catalyst Loading and Unloading: Compliance with the opacity limitations in Conditions 35.1, 35.2 and 35.3 shall be monitored as follows:

35.8.1.1 Established standard operating procedures (SOPs) minimizing visible emissions are followed. These SOPs shall be in written form and made available to the Division for inspection upon request.

35.8.1.2 An EPA Reference Method 9 opacity reading shall be conducted each time reformer catalyst is loaded and/or unloaded.

35.8.1.3 Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

35.8.1.4 All opacity observations shall be performed by an observer with current and valid Method 9 certification. Results of Method 9 readings and a copy of the certified Method 9 reader's certificate shall be kept on site and made available to the Division upon request.

35.8.1.5 Records of the date and time of each loading/unloading activity shall be maintained on site for Division inspection upon request.

36. Particulate Matter Emission Limits – Fuel Burning Equipment

36.1 No owner or operator shall cause or permit to be emitted into the atmosphere from any fuel burning equipment, particulate matter in the flue gases which exceeds the following:

For fuel burning equipment with designed heat inputs greater than 1 x 10^6 BTU per hour, but less than or equal to 500 x 10^6 BTU per hour, the following equation will be used to determine the allowable particulate emission limitation.

$PE = 0.5(FI)^{-0.26}$

Where: PE = Particulate Emission in Pounds per million BTU heat input.

FI = Fuel Input in Million Btu per hour.

(Colorado Regulation No. 1, III.A.1.b)

In the absence of credible evidence to the contrary, compliance with this emission limit shall be presumed since only gaseous fuel is permitted to be used as fuel. The permittee shall maintain records to verify that only gaseous fuel is used.

37. SV1 Soil Vapor Extraction (SVE) Unit – RSI Engine

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Non-Road Engine Status	37.1	Permit is Required if Engine is to Remain in One Location for More than 12 Consecutive Months		See Condition 37.1	
VOC Emissions from Soil Vent	37.2	VOC Emissions from Soil Vent Shall be Routed to the Engine for Destruction and Shall not Exceed 0.08 Tons/year	2.96×10^{-2} lb/MMBtu	Recordkeeping Calculation	Monthly
Hours of SVE Unit Operation	37.3			Recordkeeping	Monthly

37.1 The internal combustion engine associated with SV1 shall not remain in one location for more than twelve (12) consecutive months unless a construction permit or a modification to this Title V permit is issued prior to the end of the twelve month period. A location is any single site at a building, structure, facility (e.g. refinery), or installation. Any engine (or engines) that replace an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period.

37.2 Emissions from the soil vent shall be routed to the RSI engine for destruction and shall not exceed 0.08 tons/year. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section III.A.6 and Part C, Section X based on requested emissions indicated on the APEN submitted on 9/26/08) Compliance with the annual limits shall be monitored by calculating emissions monthly using the above emission factor (from AP-42, Section 3.2 (dated 7/00), Table 3.2-3), the SVE Unit engine heat input rate (0.60 MMBtu/hr) and hours of operation for the SVE Unit in the following equation:

Tons/mo = [EF (lb/MMBtu) x 0.60 MMBtu/hr x Monthly hours of operation (hr/mo)]/2000 lb/ton

Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

37.3 Hours of operation from the SVE Unit shall be monitored and recorded monthly. Hours of operation shall be used to calculate monthly emissions as specified in Condition 37.2.

38. Facility Wide Requirements

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
SO_2 Emissions – Colorado Regulation No.1	38.1	0.3 lb/bbl oil processed/day		Recordkeeping Calculation	Daily Monthly
Barrels of Oil Processed	38.2			See Condition 38.2	
Facility Access	38.3	See Condition 38.3		Certification	Annually
Requirements for Heaters and Boilers (Consent Decree H-01-4430)	38.4	See Condition 38.4		See Condition 38.4	
General Recordkeeping, Record Retention and Reporting (Consent Decree H-01-4430)	38.5	See Condition 38.5		Progress Reports	Semi-Annually
Emergency Notifications **– State-only**	38.6	See Condition 38.6		See 38.6	
Fenceline Monitoring **– State-only**	38.7	Begin Fenceline Monitoring by January 1, 2023		See Condition 38.7	
Annual Emissions Report - **State-only**	38.8			See Condition 38.8	
Quarterly Community Report - **State-only**	38.9			See Condition 38.9	
Disseminate Continuous Emission Monitoring Data to the Public - **State-only**	38.10			See Condition 38.10	
Disseminate Continuous Emission Monitoring Data to the Division – **State-only**	38.11				
Community-Based-Monitoring Stations – **State-only**	38.12				
Enhanced Training and Training Tools	38.13				
Procedures in Digital Format and Procedure Implementation	38.14				

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

38.1 New sources of sulfur dioxide shall not emit or cause to be emitted sulfur dioxide in excess of the following process-specific limitations. 0.3 lbs. sulfur dioxide, for the sum of all SO_2 emissions from a given refinery per barrel of oil processed. (Averaged over a daily 24 hour period, i.e. midnight through 23:59.) (Regulation No. 1, Section VI.B.4.e)

Daily SO_2 emissions from individual SO_2 emitting equipment from all equipment at the facility shall be calculated as required by Section II of this permit for the equipment located at Plants 1 and 3 and Section II of Operating Permit 95OPAD108 for equipment located at Plant 2. Daily SO_2 emissions shall be summed together and divided by the daily barrels of oil processed for the month as determined by Condition 38.2 to assess compliance with the SO_2 emission limitation. The daily compliance calculations for each month shall be made by the end of the subsequent month.

38.2 The daily refinery throughput of daily barrels per day shall be determined and used to assess compliance with the SO_2 emission limitation in Condition 38.1. The refinery total charge is based on the amount of crude oil charged to the No. 1 and 2 sweet and sour (No. 3) crude units and purchased intermediate products charge to process units. The barrels of oil processed includes the amount of crude oil and intermediate products charged to the following processes:

38.2.1 Charge to the #1 and #3 crude units

38.2.2 Charge to the #2 crude unit

38.2.3 Purchased intermediate coker gas oil charge to the #4 HDS

38.2.4 Purchased intermediate charge to the #2 naphtha hydrotreater/reformer

38.2.5 Purchased intermediate charge to the #2 FCCU

38.2.6 Purchased sweet naphtha or gas oil charge to tankage

The quantity of daily refinery throughput shall be determined as follows:

38.2.7 The barrels charged to the process units identified in Conditions 38.2.1 through 38.2.5 are continuously metered. The charge rates for those process units shall be totaled over the daily (24-hr period, i.e. from midnight to 23:59) period and recorded.

38.2.8 Since purchased intermediates received in tanks may be mixed with intermediates produced on-site, direct measurement of this source of charge cannot be measured directly. The daily throughput shall be determined by one of the following methods:

38.2.8.1 If the purchase is equal to or less than 1,000 barrels, the entire purchase will be assumed to be charged on the day it is received.

38.2.8.2 If a purchase is made that enables a unit to run at a higher rate (i.e. the unit was operating at less than 100% of its capacity), the difference between the pre-purchase charge rate and the post-purchase charge rate will be assumed to be the charge rate for the purchased intermediate.

38.2.8.3 If the purchase does not fit into one of the above scenarios, then the charge rate will be based on process knowledge, operating information and engineering judgment.

For any intermediate purchases, supporting information and calculations will be maintained for Division review upon request.

38.2.9 For purposes of assessing compliance with the SO_2 limit in Condition 38.1, the average daily amount of oil processed for each calendar month will be determined by adding crude charge for the month plus any intermediate charges (throughput identified in Conditions 38.2.1 through 38.2.6) and dividing the total barrels charged by the number of days during that month that any refinery SO_2 source operating. The average daily value for a month shall be calculated by the end of the following month.

38.3 Public access to this facility shall be precluded by a fence. (Colorado Construction Permits 09AD1351 and 10AD1768)

38.4 The following requirements from Consent Decree H-01-4430 (entered April 30, 2002, 1st Amendment entered August 8, 2003, 2nd Amendment entered October 2006) apply to heaters and boilers at this facility:

38.4.1 The permittee shall submit annual updates (“Updates”) as set forth in paragraph 61 of the Consent Decree.

38.4.2 The Control Plan and Updates shall be certified as provided in Condition 38.4 of this permit. (Paragraph 62)

38.4.3 The requirements of this Condition 38.4 do not exempt the permittee from complying with any and all Federal, state or local requirements that may require technology upgrades based on actions or activities occurring after the Date of Entry of the First Amendment to the Consent Decree. (Paragraph 67)

38.4.4 The permittee shall retain all records required to support their reporting requirements under this Condition 38.4, for the life of the Consent Decree, unless other regulations require the records to be maintained longer. (Paragraph 68)

38.4.5 For the life of the Consent Decree, the permittee shall not commence burning of any liquid fuel in its heaters and boilers. (Paragraph 70)

38.5 The following requirements from Consent Decree H-01-4430 (entered April 30, 2002, 1st Amendment entered August 8, 2003, 2nd Amendment entered October 2006) apply to general recordkeeping, record retention and reporting:

38.5.1 For the purposes of the Consent Decree, any requirement for the permittee to consult, obtain approval or submit any type of information to EPA or the United States, including reports, analyses, or data, shall be construed as imposing identical requirements from the permittee to the Division. The permittee shall retain all records required to be maintained in accordance with the Consent Decree for a period of five (5) years after termination of the Consent Decree, unless other regulations require the records to be maintained longer. (Paragraph 211)

38.5.2 All notices, reports or any other submission of the permittee to be certified, with the exception of Semi-Annual Progress Reports, shall contain the certification set forth in paragraph 212 of the Consent Decree.

38.5.3 The permittee shall submit a Semi-Annual Progress Report ("semi-annual report") to EPA and the Division by January 31 and July 31 until termination of the Consent Decree. In addition to any other information specifically required to be submitted per other Consent Decree requirements, the report shall contain the information listed in paragraphs 213, 213A and 213B of the Consent Decree.

38.5.4 The Semi-Annual Progress Reports shall be certified by a refinery manager or company official responsible for environmental management and compliance at the refineries covered by the report, as set forth in paragraph 214 of the Consent Decree.

38.6 **State-Only Requirement:** Suncor shall:

38.6.1 Conduct outreach to representatives of the community in the relevant area to discuss communications regarding the occurrence of an incident, including (§ 25-7-141.(4)(a)):

38.6.1.1 Methods by which the covered facility can disseminate information to the community in the relevant area and methods by which community members can contact the covered facility regarding an incident (§ 25-7-141.(4)(a)(I)) ; and

38.6.1.2 Provisions for communications in the relevant languages (§ 25-7-141.(4)(a)(II)). (§ 25-7-141.(4)(a))

38.6.2 "Incident" means the emission by a covered facility of an air pollutant at a rate or quantity that exceeds allowable emissions as a result of anticipated or unanticipated circumstances, including a malfunction, start-up, shutdown, upset, or emergency. (§ 25-7-141.(2)(f))

38.6.3 "Notification threshold" means acute exposure levels with an averaging time of one hour as established by the division pursuant to subsection (5)(a)(III) of this section. (§ 25-7-141.(2)(j))

The notification thresholds from Suncor's fenceline monitoring plan (beginning January 1, 2025) are:

Hydrogen cyanide: 1.3 parts per million

Hydrogen sulfide: 0.36 parts per million

Benzene: 18 parts per million

The interim notification thresholds for Suncor's initial system (valid until December 31, 2024) are:

Hydrogen cyanide: 1.3 parts per million

Hydrogen sulfide: 1.0 parts per million

Benzene: 18 parts per million

38.6.4 Use an emergency notification service through which the covered facility will, as soon as possible, communicate in the relevant languages with, and make data available to, the community in the relevant area and the division regarding the occurrence of an incident or an exceedance of a notification threshold identified by a fenceline monitoring system. (§ 25-7-141.(4)(b))

38.6.5 For two years, maintain a record of all communications made through an emergency notification service, including whether any other action was taken in response to the incident or exceedance of a notification threshold, which record must be available to the public. (§ 25-7-141.(4)(b.5))

38.7 **State-only Requirement:** Beginning on January 1, 2023, a covered facility that is a petroleum refinery shall conduct fenceline monitoring of covered air toxics in real time and shall disseminate all fenceline monitoring data to the public as described in subsection (5)(h) of this section. (§ 25-7-141.(5)(a)(I))

38.7.1 The notification thresholds from Suncor's fenceline monitoring plan (beginning January 1, 2025) are:

Hydrogen cyanide: 1.3 parts per million

Hydrogen sulfide: 0.36 parts per million

Benzene: 18 parts per million

The interim notification thresholds for Suncor's initial system (valid until December 31, 2024) are:

Hydrogen cyanide: 1.3 parts per million

Hydrogen sulfide: 1.0 parts per million

Benzene: 18 parts per million

38.7.2 Each covered facility shall collect real-time data from the fenceline monitoring system, shall maintain records of the data, and shall disseminate the data to the division and the public. (§ 25-7-141.(5)(h)) The dissemination must:

38.7.2.1 Be available in real time on a website maintained by the covered facility and include a map of all fenceline monitoring equipment locations and the ability to access historical fenceline monitoring data (§ 25-7-141.(5)(h)(I));

38.7.2.2 Be in the relevant languages spoken in the relevant area (§ 25-7-141.(5)(h)(II));

38.7.2.3 Include descriptions in the relevant languages of covered air toxics and their possible health effects as specified by the federal centers for disease control and prevention (§ 25-7-141.(5)(h)(III)); and

38.7.2.4 Include data about air concentrations of any hazardous air pollutant other than covered air toxics that the division determined under subsection (5)(e) of this section must be included in the fenceline monitoring plan. (§ 25-7-141.(5)(h)(IV)).

38.7.2.5 Consistent with the covered facility's approved plan, reports summarizing fenceline monitoring operations and the three covered air toxics data will be posted to the public website quarterly, within 60 days following the end of the quarter for which the data were collected. The reports will summarize open-path and meteorological data, fenceline monitoring operations, any significant changes to the monitoring system, downtime, and quality assurance activities and results. See Appendix C for an example quarterly report template. A downloadable data packet file containing a data summary for the three covered air toxics and meteorological data with basic statistics, a list of hours during which exceedance events occurred, a list of periods during which data was invalidated, results from verification activities (e.g., calibrations, QC checks, and QA), and the hourly averaged data along with corresponding detection limits and data qualifiers will also be posted on the website along with the report, within 60 days following the end of the quarter for which the data were collected.

38.7.3 The permittee shall submit an application to revise the permit to address any new pollutants for which fenceline monitoring is required, or other changes to the plan, due to the fenceline monitoring plan updates required by § 25-7-141.(5)(i) (§ 25-7-141.5(g)).

38.8 **State-only Requirement:** Suncor is required to submit a comprehensive annual emissions report to the Division detailing total actual emissions from the facility and the amount of emissions that occurred as a result of exceedances of any permit limit. Suncor is required to submit a proposed report format for Division review and approval within 90 days after permit issuance. The annual emissions report (using the Division-approved format) must be submitted on June 30 of each year.

38.9 **State-only Requirement:** Suncor is required to submit a quarterly community compliance report that will identify in an easy to understand format any emissions violations at the facility during the previous quarter.

38.10 **State-only Requirement:** Suncor must disseminate continuous emissions monitoring data to the public via a web-based system. Within 60 days of issuance of this permit, Suncor must submit a proposed plan to the Division for review and approval. The plan must include Suncor's proposal for displaying air monitoring data from Plants 1 & 3 Continuous Emissions Monitors (CEMs) as well as meteorological data on a dedicated website available to the public. Suncor must implement the CEMS data sharing plan within 60 days of Division approval.

38.11 **State-only Requirement:** Dissemination of Real-Time Data to the Division

38.11.1 On and after January 1, 2025, as technically feasible as determined by the Division, a petroleum refinery in the state shall disseminate to the Division, in real time through an application programming interface, push data gathered through (§ 25-7-146 (2)(a)):

38.11.1.1 Continuous emission monitoring systems and continuous monitoring systems required under state or federal law (§ 25-7-146 (2)(a)(I)), including the following:

a. Continuous emissions monitoring systems (CEMS);

b. Continuous opacity monitoring systems (COMS);

c. Predictive emissions monitoring systems (PEMS);

d. Continuous parametric monitoring systems (CPMS);

e. Hydrogen sulfide continuous monitoring systems for refinery fuel gas and flare gase, per 40 CFR Part 60, §§60.104(a)(1) (NSPS J), and 60.102a(g)(1)(ii) and §60.103a(h) (NSPS Ja); and

f. Continuous video surveillance cameras recording images of the flare flame to demonstrate compliance with the applicable opacity standard for the flare;

38.11.1.2 Fenceline monitoring systems as required under § 25-7-141(5) (Condition 38.7) (§ 25-7-146 (2)(a)(II));

38.11.1.3 Community-based monitoring required under § 25-7-141 (6) (Condition 38.11.4) (§ 25-7-146 (2)(a)(III)); and

38.11.1.4 Compliance with a state-issued compliance order (§ 25-7-146 (2)(a)(IV)).

38.11.2 The data disseminated to the Division pursuant to subsection (2)(a) of C.R.S 25-7-146 must be provided through the push in a one-minute averaged resolution (§ 25-7-146 (2)(b)).

38.11.3 The Division shall determine the format by which a petroleum refinery must transmit the data to the Division (§ 25-7-146 (2)(c)).

38.11.4 For the purposes of this condition, the definitions described in § 25-7-146 (4)(a) through (i) apply.

38.12 **State-only Requirement:** Community-Based Monitoring Systems

38.12.1 On or before December 31, 2024, a petroleum refinery shall install and operate at least six community-based monitoring systems (as described in 38.12.2) to monitor, at a minimum, for (§ 25-7-146 (3)(a)(I) through (XIV));

38.12.1.1 Benzene;

38.12.1.2 Toluene;

38.12.1.3 Ethylbenzene;

38.12.1.4 Xylene;

38.12.1.5 Carbon monoxide;

38.12.1.6 Nitrogen dioxide;

38.12.1.7 $PM_{2.5}$;

38.12.1.8 Hydrogen sulfide

38.12.1.9 Sulfur dioxide;

38.12.1.10 Total volatile organic compounds;

38.12.1.11 Temperatue;

38.12.1.12 Relative humidity;

38.12.1.13 Wind speed; and

38.12.1.14 Wind direction.

38.12.2 At a minimum, the community-based monitoring system locations that must be installed and operated per the requirements of this Condition are as follows:

a. CM1 – Rose Hill Elementary School. GPS Coordinates: 39.80164, -104.90882. Cross Streets: E. 58th Ave. & Oneida St., Commerce City

b. CM2 – Suncor Refinery Business Center. GPS Coordinates: 39.79630, -104.95727. Cross Streets: Brighton Blvd. & York St, Commerce City.

c. CM6 – Focus Points Family Resource Center. GPS Coordinates: 39.78436, -104.95663. Cross Streets: Columbine St. & 48th Ave., Denver.

d. CM7 – Kearney Middle School. GPS Coordinates: 39.80888, -104.91545. Cross Streets: E. 62nd Ave. & Kearny St., Commerce City

e. CM8 – Monroe. GPS Coordinates: 39.81560, -104.94503. Cross Streets: Monroe St. & 64th Ave., Denver.

f. CM10 – Alsup Elementary School. GPS Coordinates: 39.820268, -104.936616. Cross Streets: East 68th Ave. & Birch St., Commerce City.

38.12.2.2 Suncor may provide a written request to the Division that alternative community-based monitoring system locations be installed and operated instead of the stations listed in this condition. Suncor must provide technical justification for the proposed alternative location, and the alternative location is subject to Division-approval.

38.12.3 The community-based monitoring systems installed and operated pursuant to this subsection (3) must be installed, certified, and operated in accordance with a plan developed by the Division (§ 25-7-146 (3)(b)).

38.12.4 For the purposes of this condition, the definitions described in § 25-7-146 (4) apply.

38.13 Enhanced Training and Tools

38.13.1 For each emission unit in this Title V operating permit for which emission limits or other operational requirements are specified in federal and state regulations, the following requirements apply (note that the regulatory basis for these conditions for each emission unit are the underlying regulatory and/or construction permit condition requirements):

38.13.1.1 A comprehensive listing of all environmental operating limits (EOLs) shall be developed within 90 days of issuance of this Title V operating permit.

For the purposes of this condition, EOLs refer to any constraints imposed by regulatory requirements and permit conditions. For example this may include, but is not limited to a comprehensive listing of all point source emission limits, throughput limits, fired duty limits (for heaters and boilers), firebox temperature thresholds for incinerators, vapor pressure limits for storage tanks, inspection requirements, operating time limits for engines, monitoring requirements (including quality assurance requirements), reporting requirements, etc.

38.13.1.2 The EOLs shall be inserted into process unit operating manuals and/or maintenance and inspection procedures, as applicable, within 180 days of permit issuance.

38.13.1.3 Applicable Suncor operators, operation supervisors, engineering staff, maintenance personnel, and inspection staff shall be trained on the EOLs for their areas of responsibility within 365 days of permit issuance, or within 180 days of being hired by Suncor, whichever is later.

38.13.1.4 Each applicable Suncor staff member must demonstrate their understanding of the material via a written assessment.

38.13.1.5 All documentation associated with the development and implementation of the EOL program shall be retained onsite in a readily available format for Division inspection upon request. These records include, but are not limited to: relevant process unit operating manuals, maintenance and inspection procedures, employee staff lists, and EOL assessments.

38.13.2 For each emission unit in this Title V operating permit for which federal New Source Performance Standards under 40 CFR Part 60, or National Emission Standards for Hazardous Air Pollutants under 40 CFR Parts 61 or 63 apply, the following requirements apply (note that the regulatory basis for these conditions for each emission unit are the underlying General Duty obligations in the applicable NSPS (40 CFR Part 60, Subpart A, §60.11(d)) or NESHAP (e.g., 40 CFR Part 63, Subparts UUU and CC at §63.1570(c) and §63.642(n)):

38.13.2.1 Suncor shall implement a training department staffed by trainers within 24 months of issuance of this Title V operating permit. Each major refinery complex (e.g., catalytic cracking/alkylation, hydroprocessing/reforming, distillation, sulfur management, and utilities) shall have a trainer with appropriate operational knowledge within their assigned complex. The trainers' primary duties shall be the development and implementation of a detailed training program for all newly hired operators, and refresher training for all existing operators covering the objective of operating equipment in a manner that prevents deviations from Title V operating permit requirements. Trainers shall also develop detailed materials for insertion into process unit operating manuals designed to meet this same objective. All training materials shall be revised, as needed, following process equipment changes and operating changes. An assessment of the need to revise the training material shall also be included as a Management of Change (MOC) (or equivalent) checklist item.

38.13.2.2 A training simulator for FCCU operation shall be developed and implemented within 24 months of permit issuance. The simulator shall be programmed to emulate typical upset scenarios that have been experienced at the Plant 1 FCCU (these may include, but are not limted to steam and cooling water supply disruptions, electrical power outages, and feedstock supply abnormalities), as well as other abnormal operation scenarios as recommended by outside technical experts or the Division. The training simulator programmed scenarios shall be revised within three (3) months of any FCCU upset that occurs that is outside the parameters of existing scenarios. The simulator shall also be programmed to emulate triggering the unit's automated shutdown system if recovery from the simulated upset is not possible. All FCCU console operators shall undergo training on the simulator within three (3) months of the system's availability and shall undergo refresher training every twelve (12) months thereafter, or within three (3) months of any substantive updates to the training simulator.

38.13.2.3 Suncor shall maintain records on site for Division inspection upon request all such records that are relevant to demonstrate compliance with the requirements in Condition 38.13.2. These may include, but are not limited to training staff lists, training program materials, process unit operating manuals, employee training records, documentation of training program changes and updates, Operator Response Action lists, descriptions of training simulations and parameters, etc. The Division may request that Suncor maintain additional records to demonstrate compliance with this condition if the Division determines that the records submitted by Suncor are insufficient. Deviations from the requirements of Condition 38.13 shall be reported in the semi-annual report to the Division.

38.14 Procedures in Digital Format and Procedure Implementation

38.14.1 For each emission unit in this Title V operating permit for which federal New Source Performance Standards under 40 CFR Part 60, or National Emission Standards for Hazardous Air Pollutants under 40 CFR Parts 61 or 63 apply, the following requirements apply (note that the regulatory basis for these conditions for each emission unit are the underlying General Duty obligations in the applicable NSPS (40 CFR Part 60, Subpart A, §60.11(d)) or NESHAP (e.g., 40 CFR Part 63, Subparts UUU and CC at §63.1570(c) and §63.642(n)):

38.14.1.1 Within 12 months of the issuance date of this Title V permit, Suncor shall implement a program ensuring that all operating, maintenance, and inspection procedures for affected air emission sources and supporting ancillary equipment are available in digital format (which may include electronic files in PDF format) to its employees.

a. The equipment needed to access these procedures shall be present and readily available in control rooms, maintenance shops, operator shelters, and in the field via handheld devices, as appropriate.

b. These procedures must be updated as needed to include learnings from incident investigations. An assessment of the need to update procedures must be included on Suncor's Management of Change (MOC) (or equivalent) checklist.

38.14.1.2 Within 12 months of the issuance date of this Title V permit, whenever process units are started-up or shutdown, and when significant pieces of equipment (as determined by the Division) are either placed in service or removed from service, operators shall document the completion of each procedural step required by the relevant procedure by maintaining an easily accessible log, which includes operator initial and the date and time of the completion of the procedure, for Division inspection upon request. If any deviation from a procedure is necessary, the nature of that deviation and the reason for the change must be documented along with confirmation that a unit supervisor or shift supervisor approved the change. Completed procedure documentation with signoffs shall be retained on site for Division inspection upon request. If an emergency or unsafe event precludes compliance with this condition, Suncor shall maintain records indicating the nature of the emergency or unsafe event, and must provide these records to the Division within seven (7) days after the conclusion of the event.

38.14.1.3 Suncor shall maintain records on site for Division inspection upon request all such records that are relevant to demonstrate compliance with the requirements in Condition 38.14. These may include, but are not limited to digital operating, maintenance, and inspection procedures, lists of locations and equipment available to access the procedures, logs of updates to the procedures, procedure completion logs as described in Condition 38.14.1.3, etc. The Division may request that Suncor maintain additional records to demonstrate compliance with this condition if the Division determines that the records submitted by Suncor are insufficient. Deviations from the requirements of Condition 38.14 shall be reported in the semi-annual report to the Division.

39. Reasonably Available Control Technology – General Requirements for Storage and Transfer of Volatile Organic Compounds - Colorado Regulation No. 24, Part B, Section I

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Maintenance and Operation of Storage Tanks	39.1	Minimize Vapor Loss		Inspection	Semi-Annually
Transfer (Excluding Petroleum Liquids)	39.2	See Condition 39.2		Tank Design	

Note that the language below is from Colorado Regulation No. 24, adopted by the Colorado Air Quality Control Commissions (AQCC) on April 20, 2023 (effective June 14, 2023). However, if revisions to Colorado Regulation No. 24, Part B, Section I are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part B, Section I.

39.1 Maintenance and Operation of Storage Tanks and Related Equipment – Section I.A

All storage tanks are subject to these requirements

All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves, shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. When an analyzer is used, testing and monitoring shall be conducted as in Colorado Regulation No. 24, Part B, Section VI.C.3.

Monitoring: Detectable vapor loss shall be determined using one of the methods described above, at least semi-annually. Records of the monitoring method and results shall be maintained for Division inspection upon request.

39.2 Transfer (excluding Petroleum Liquids) – Section I.B

Tank T7208 is subject to this requirement.

Except as otherwise provided in this regulation, all volatile organic compounds transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

In the absence of credible evidence to the contrary, compliance with this requirement is presumed based on the design and construction of T7208.

40. Reasonably Available Control Technology – Storage of Highly Volatile Organic Compounds - Colorado Regulation No. 24, Part B, Section II

Storage Tanks D-811, T81, T82, D-812, D-813, D-814, T90, T91, T92, and T400 are subject to these requirements. These tanks operate under pressure and have emissions less than de minimis reporting levels and are not subject to any other requirements.

Note that the language below is from Colorado Regulation No. 24, adopted by the Colorado Air Quality Control Commissions (AQCC) on April 20, 2023 (effective June 14, 2023). However, if revisions to Colorado Regulation No. 24, Part B, Section II are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part B, Section II.

40.1 Highly volatile organic compounds shall be stored:

40.1.1 In a pressure tank which is at all times capable of maintaining working pressures sufficient to prevent vapor loss to the ambient air (Section II.A.1); or

40.1.2 With methods and/or equipment approved by the Division in writing pursuant to the request of the person owning or operating the storage facility. (Section II.A.2)

40.2 Vapor loss shall be determined visually, by presence of frost or condensation at the point of leakage, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. When an analyzer is used, testing and monitoring shall be conducted as in Colorado Regulation No. 24, Part B, Section VI.C.3. (Section II.B.2)

Monitoring for detectable vapor loss shall be determined using one of the methods described above, at least semi-annually. Records of the monitoring method and results shall be maintained for Division inspection upon request.

41. Reasonably Available Control Technology for Storage and Transfer of Petroleum Liquid - Colorado Regulation No. 24, Part B, Section IV

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
General Requirements	41.1	See Condition 41.1			
Requirements for Tanks > 40,000 Gallons	41.2	Fixed Roof Tanks - See Condition 41.2.1		Inspection	Semi-Annually & when out of service
		Above Ground Tanks External Surfaces - See Condition 41.2.2			
		External Floating Roofs - See Condition 41.2.3		Inspection	Semi-annually
Transfer at Terminals	41.3	See Condition 41.3		Testing	See Condition 41.3
Transport Vehicles	41.4 and 41.5	Loading Restrictions		See Conditions 41.4.1 and 41.5	
Tanks < 40,000 gallons	41.6	Submerged Fill Pipe and Vapor Control System		See Condition 41.6	

Note that the language below is from Colorado Regulation No. 24, adopted by the Colorado Air Quality Control Commissions (AQCC) on April 20, 2023 (effective June 14, 2023). However, if revisions to Colorado Regulation No. 24, Part B, Section IV are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part B, Section IV.

41.1 General Requirements – Section IV.A.1

No person shall build, install, or permit the building or installation of any rotating pump or compressor handling any type of petroleum liquid unless said pump or compressor is equipped with mechanical seals or other equipment of equal efficiency. If reciprocating-type pumps and compressors are used, they shall be equipped with packing glands properly installed, in good working order, and properly maintained so that no detectable emissions occur from the drain recovery systems.

41.2 Storage of Petroleum Liquid in Tanks Greater than 151,412 liters (40,000 gallons) – Section IV.B.2

41.2.1 Fixed Roof Tanks with Internal Floating Roofs – Section IV.B.2.a

Storage of petroleum liquids in fixed roof tanks are subject to the requirements in Section IV.B.2.a. (Tanks T96, T97, T116, T4504, T4516, T4517 and T4518 are subject to this condition.) Note: Records of inspection results shall be kept five years.

Note that tanks T4504, T4516, T4517 and T4518 meet the requirements in Section IV.B.2 using a closed vent system and control device as provided for in Section IV.B.2.a.(i)(B). In the absence of credible evidence to the contrary compliance with the control device requirements (Section IV.B.2.a.(i)(C)) and methods for determining control efficiency (Section IV.B.2.a.(i)(D)) is presumed provided these tanks are in compliance with the BWON control device requirements (Condition 65).

41.2.2 Above Ground Storage Tanks – Section IV.B.2.b

Above ground storage tanks used for the storage of petroleum liquid shall have all external surfaces coated with a material which has a reflectivity of solar radiation of 0.7 or more. Methods A or B of ASTM E424 shall be used to determine reflectivity. Alternatively, any untinted white paint may be used which is specified by the manufacturer for such use.

This provision shall not apply to written symbols or logograms applied to the external surface of the container for purposes of identification provided such symbols do not cover more than 20% of the exposed top and side surface area of the container or more than 18.6 square meters (200 square feet), whichever is less. (Section VI.B.2.b) (Except for the pipeline receipt station sump, T182, T4502, T4503, T4507, T4508, T4514 and T4515 all tanks covered by this permit are subject to this condition)

41.2.3 Seals on External Floating Roof Tanks – Section IV.B.2.c

All petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 150,000 liters (40,000 gallons), located in ozone non-attainment areas, are subject to the applicable monitoring, operating, and recordkeeping requirements in Section IV.B.2.c. (Tanks T1, T34, T55, T58, T60, T67, T70, T75, T77, T78, T80, T775, T776, T777, T778, T2010 and T4501 are subject to this condition. Tanks T62, T64, T65, T66, T72 and T774 are subject only to the recordkeeping provisions of Section IV.B.2.c.(ii)(C)).

41.3 Loading Facilities Classified as Terminals – Section IV.C.2 (R101 and R102 are subject to this condition)

41.3.1 The owner or operator of a terminal subject to this subsection shall equip the terminal with proper loading equipment and shall follow the loading procedures listed below (Section IV.C.2.b):

41.3.1.1 Install dry-break loading couplings to prevent petroleum liquid loss during uncoupling from vehicles. (Section IV.C.2.b.(i))

41.3.1.2 Install a vapor collection and disposal system which gathers vapor transferred from vehicles being loaded. The system shall include devices to prevent the release of vapor from vapor recovery hoses not in use. (Section IV.C.2.b.(ii))

41.3.1.3 Use operating procedures to ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use. (Section IV.C.2.b.(iii))

41.3.1.4 Provide for the prevention of overfilling of transport vehicles with loading pump shut-offs, set stop meters, or comparable equipment. (Section IV.C.2.b.(iv))

41.3.1.5 Operate all recovery and disposal equipment at a back pressure less than the pressure relief valve setting of transport vehicles. (Section IV.C.2.b.(v))

41.3.1.6 Prevent the release of petroleum liquid on the ground from transport vehicles. Provision shall be made to remove any undelivered petroleum liquid with closed drainage devices. (Section IV.C.2.b.(vi))

41.3.1.7 Maintain and operate final recovery and disposal equipment or devices in the vapor control system (i.e., control devices) so as to emit no more than 80 milligrams of volatile organic compounds per liter of gasoline being loaded. Such disposal devices shall be approved by the Division. (Section IV.C.2.b.(vii))

41.3.1.8 Prevent loading of petroleum liquid into transport vehicles which do not have valid leak-tight certification as required in Section IV.D. No truck shall be loaded unless a valid certification sticker is displayed, or a certification letter is carried in the truck. (Section IV.C.2.b.(viii))

41.3.1.9 Follow all control procedures to prevent leaks as specified in Section VII. (Section IV.C.2.b.(ix))

41.3.2 Control devices shall meet the applicable requirements including recordkeeping of Part C Sections I.A.3.a, b, c, and e, and I.A.8.a and b. (Section IV.C.2.c)

41.3.3 The applicable methods of 40 CFR 60.503 (September 14, 1989), or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices. (Section IV.C.2.d)

41.3.4 The method set forth in Appendix A of "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals" October 1977, EPA-450/2-77-026 shall be used to test emission points other than control devices. (Section IV.C.2.e)

In the absence of credible evidence to the contrary compliance with Conditions 41.3.2 through 41.3.4 is presumed provided the rail rack and the rail rack VCU meet the requirements in Condition 24 and the truck rack and truck rack flare meet the requirements in Condition 25.

41.4 Transport Vehicles – Section IV.C.4.a (R101 is subject to this condition.)

41.4.1 Rail cars shall be loaded only at facilities which allow for the following (Section IV.C.4.a):

41.4.1.1 A submerged fill pipe which reaches within 15.24 cm (6 in.) of the bottom of the tank. (Section IV.C.4.a.(i))

41.4.1.2 Vapor collection and/or disposal equipment designated and operated to recover vapors displaced during the loading of the rail car. (Section IV.C.4.a.(ii))

41.4.1.3 A vapor-tight seal around the tank car hatch and the loading equipment. (Section IV.C.4.a.(iii))

41.5 Control of Volatile Organic Compound Leaks from Gasoline Transport Trucks - Section IV.D.2.a (R102 is subject to this condition.)

41.5.1 No terminal operator, when monitoring the gasoline loading operation and no owner or operator of a gasoline transport truck shall allow a gasoline transport truck subject to this Section IV.D. to be filled with a VOC with Reid Vapor Pressure of 4.0 or greater unless the gasoline tank truck meets the requirements in Section IV.D.2.a. (Section IV.D.2.a)

Suncor shall maintain a computerized system with information on certified trucks with an interlock system that prevents the loading of uncertified trucks.

41.6 Storage of Petroleum Liquid in Tanks Equal to or Less than 151,412 liters (40,000 gallons) – Section IV.B.3 (Tanks D-20, T4502, T4503, T4507 and T4508 are subject to these requirements.)

41.6.1 The owner or operator of storage tanks at a gasoline dispensing facility (service station) or other facility not addressed in Sections IV.C.2. or IV.C.3., which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and all vapors displaced from the storage tank are transferred to the delivery vessel being unloaded using a properly maintained, functioning, and leak-tight vapor collection system, as in accordance with applicable provisions of Appendix B and Section VII., if the tank meets the requirements in Section IV.B.3.b.(i) or (ii). (Section IV.B.3.b) Tanks subject to these requirements shall meet the requirements in Sections IV.B.3.c through h, as applicable.

Tanks D-20, T4502, T4503, T4507 and T4508 are subject to the requirements in Section IV.B.3.c, d, e and g. In the absence of credible evidence to the contrary, compliance with the control device requirements in Section IV.B.3.g is presumed provided these tanks are in compliance with the BWON control device requirements (Condition 65).

42. Reasonably Available Control Technology for Crude Oil – Colorado Regulation No. 24, Part B Section V

Tanks T58, T775 and T776 are subject to these requirements.

Note that the language below is from Colorado Regulation No. 24, adopted by the Colorado Air Quality Control Commissions (AQCC) on April 20, 2023 (effective June 14, 2023). However, if revisions to Colorado Regulation No. 24, Part B, Section V are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part B, Section V.

42.1 Equipment

Pumps and compressors handling crude oil shall be subject to the provisions of Section IV.A (Condition 41.1). (Section V.B)

42.2 Storage

Except as provided in Section V.A.2., crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Sections IV.B.1.b. and IV.B.2 (Condition 41.2). (Section V.C)

43. Reasonably Available Control Technology for Petroleum Processing and Refining - Colorado Regulation No. 24, Part B, Section VI

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Wastewater Separators	43.1	Control Device and closed openings		Inspection	See Condition 43.1
Process Unit Turnarounds	43.2.1	See Condition 43.2.1		As set forth in Division approved procedure	
Blowdown System and Relief Valve Venting	43.2.2	90% combustion efficiency		Flares shall meet the requirements in Condition 53	
Vacuum Producing Systems	43.2.3	Emissions of any noncondensible VOC is not permitted		Emissions shall be routed to a flare that meets the requirements in Condition 53	
Sampling, Testing, and Measuring Ports	43.2.4	Kept in closed position except when being used		Inspection	Monthly
Control Device Requirements	43.2.5 & 43.2.6	See Conditions 43.2.5 and 43.2.6		Flares shall be operated in accordance with the requirements in Condition 53	
Equipment Leaks	43.3	Inspection and Repair		Inspection and Repair	See Section VIII.C (Condition 43.3)

Note that the language below is from Colorado Regulation No. 24, adopted by the Colorado Air Quality Control Commission (AQCC) on April 20, 2023 (effective June 14, 2023). However, if revisions to Colorado Regulation No. 24, Part B, Section VI are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part B, Section VI.

43.1 Wastewater (Oil/Water) Separators – Section VI.A

T4514 and T4515 (F201 - Plant 1 wastewater treatment system separators) and the CPI separator (F101 – Asphalt unit sewer system) are subject to this condition.

43.1.1 The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall equip the forebays and separator sections of the wastewater separators with one or more of the emission control devices listed in Part B, Section VI.A.2.a, ensuring that such device is properly installed, in good working order and properly maintained. (Section VI.A.2.a)

43.1.2 The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized. (Section VI.A.2.b)

Compliance with Conditions 43.1.1 and 43.1.2 shall be monitored as follows:

43.1.3 T-4514 and T4515 meet the requirements in Section VI.A.2.a using a closed vent system and control device as provided for in Section VI.A.2.a.(iii). In the absence of credible evidence to the contrary compliance with the control device requirements (Section VI.A.2.a.(iii)(A)) and methods for determining control efficiency (Section VI.A.2.a.(iii)(B)) is presumed provided the separators are in compliance with the BWON control device requirements (Condition 65). In addition, monitoring of T4514 and 4515 shall be conducted as follows:

43.1.3.1 Each cover seal, access hatch, and all other openings shall be checked by visual inspection quarterly as set forth in 60 CFR Part 61 Subpart FF §61.347(b) (see Condition 65.15).

43.1.3.2 The permittee shall conduct monitoring of the controlled oil-water separators on a quarterly basis in accordance with the "no detectable emissions" provisions in 40 CFR §61.347. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 to incorporate the Consent Decree (H-01-4430) requirements related to BWON. Consent Decree (H-01-4330), paragraph 117(b)) (see also Condition 23.8.3)

43.1.4 The CPI separator meets the requirements in Section VI.A.2.a using a closed vent system and control device as provided for in Section VI.A.2.a.(iii). In the absence of credible evidence to the contrary compliance with the control device requirements (Section VII.A.2.a.(iii)(A)) and methods for determining control efficiency (Section VI.A.2.a.(iii)(B)) is presumed provided the requirements in Section II, Condition 32.5 are met. In addition, monitoring of the CPI separator shall be conducted as follows:

43.1.4.1 Roof seals, access doors and other openings shall be checked by visual inspection semi-annually as set forth in 40 CFR Part 60 Subpart QQQ §60.692-3(a)(5).

43.2 Emissions from Petroleum Refineries – Section VI.B

43.2.1 Process unit turnarounds. The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for the following (Section VI.B.2):

43.2.1.1 Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

43.2.1.2 No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and

43.2.1.3 Recordkeeping of the following items. Records shall be kept for at least five years and shall be made available to the Division for review upon request.

a. Every date that each process unit is shut down.

b. The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere.

c. The approximate total quantity of volatile organic compounds emitted to the atmosphere.

43.2.2 Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency. (Section VI.B.3)

In the absence of credible evidence to the contrary, flares meeting the requirements in Condition 53 (40 CFR Part 63 Subpart CC) of this permit are presumed to be in compliance with these requirements.

43.2.3 The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensible volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by venting the noncondensible vapors to a flare or other combustion device, or compressing the vapors and adding them to the refinery fuel gas. (Section VI.B.4.a)

43.2.4 All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access. (Section VIII.B.5)

Compliance with this Condition 43.2.4 shall be monitored by inspection during a monthly walk-through. Records of inspections shall be maintained for inspection upon request.

43.2.5 Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a,b,c, and e, and I.A.8.a and b. (Section VI.B.6)

In the absence of credible evidence to the contrary, flares meeting the requirements in Condition 53 (40 CFR Part 63 Subpart CC) of this permit are presumed to be in compliance with these requirements.

43.2.6 The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60, shall be used to determine the efficiency of control devices. (Section VI.B.7)

In the absence of credible evidence to the contrary, flares meeting the requirements in Condition 53 (40 CFR Part 63 Subpart CC) of this permit are presumed to be in compliance with these requirements.

43.3 Petroleum Refinery Equipment Leaks - Section VI.C

43.3.1 The owner or operator of a petroleum refinery complex subject to this regulation shall meet the requirements set forth in Section VI.C.2.a.

43.3.2 Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use. (Section VI.C.2.b)

43.3.3 The Division, at its discretion, may require early unit turnaround based on the number and severity of tagged leaks awaiting turnaround in accordance with the provisions set forth in VI.C.2.c.

43.3.4 Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly. (Section VI.C.2.d)

43.3.5 Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60. The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound. (Section VI.C.3)

43.3.6 The owner or operator of a petroleum refinery subject to this regulation shall conduct a monitoring program consistent with the following provisions (Section VI.C.4.a.(i)):

43.3.6.1 Pump seals, piping valves in light liquid service, process drains and heat exchanger flanges and other accessible flanges in VOC service shall be monitored yearly using the method specified in Section VI.C.3 (Condition 43.3.5). Components in heavy liquid service are exempt from the requirements in this paragraph (Section VI.C.4.a.(i)(A))

43.3.6.2 Compressor seals and piping valves and pressure relief valves shall be monitored quarterly using the method specified in Section VI.C.3 (Condition 43.3.5). (Section VI.C.4.a.(i)(B))

43.3.6.3 Monitor at least weekly by visual methods all pump seals. (Section VI.C.4.a.(i).C))

43.3.6.4 Monitor within 24 hours with a VOC detector and make record of any component from which VOC liquids are observed leaking. (Section

VI.C.4.a.(i)(D))

Any operator-discovered leak that cannot be monitored within 24 hours shall automatically be classified as an LDAR leak.

43.3.6.5 Components in heavy liquid VOC service shall be monitored using the method specified in Section VI.C.3 (Condition 43.3.5) within five days if evidence of a potential leak is found by visual, audible, olfactory, or any other detectable method. (VI.C.4.a.(i)(E))

43.3.6.6 Inaccessible valves and flanges shall be monitored annually or, as a minimum, at unit shutdown using the procedures of Section VI.C.2.a(v). Pressure relief devices which are connected to an operating flare header or vapor recovery device, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Conditions 43.3.6.1 through 43.3.6.5. (VI.C.4.a.(ii))

43.3.6.7 The owner or operator of a petroleum refinery, upon the detection of a leaking component as defined in Section VI.C.2.a.(iii), shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired. In addition, the owner or operator shall log the leak (including those leaks immediately repaired), per the requirements of Sections VI.C.4.b.(i) through (iii). (Section VI.C.4.a.(iii))

43.3.7 The owner or operator shall meet the recordkeeping and reporting requirements set forth in VI.C.4.b and c.

44. Reasonably Available Control Technology – Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities – Colorado Regulation No. 24, Part B, Section VII

(R101 and R102 are subject to these requirements)

Note that the language below is from Colorado Regulation No. 24, adopted by the Colorado Air Quality Control Commissions (AQCC) on April 20, 2023 (effective June 14, 2023). However, if revisions to Colorado Regulation No. 24, Part B, Section VII are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part B, Section VII.

44.1 The operator of a vapor collection or vapor control system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents (Section VII.B.1):

44.1.1 Gauge pressure from exceeding 33.6 torr (18 inches of H_2O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H_2O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility. (Section VII.B.1.a)

44.1.2 A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," December 1978, EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals. (Section VII.B.1.b)

44.1.3 Avoidable liquid leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals. (Section VII.B.1.c)

44.1.4 Division representatives may monitor for excessive back pressure as defined by Section VII.B.1.a. and vapor leakage as is defined by Section VII.B.1.b. or by detection methods incorporating sight, sound, and smell. (Section VII.B.1.d)

44.2 Repairs and Modifications

44.2.1 The operator shall within fifteen (15) days, repair and retest a vapor collection or control system that exceeds the pressure limits stated in Condition 44.1.1, above, excepting that (Section VII.B.2.a);

44.2.2 Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion. (Section VII.B.2.b)

45. 40 CFR Part 60, Subpart J – Standards of Performance for Petroleum Refineries

These requirements apply to those sources that are referred to this condition throughout the permit.

The requirements below reflect the language in 40 CFR Part 60 Subpart J as of the latest revisions to 40 CFR Part 60 Subpart J published in the Federal Register on December 1, 2015. However, if revisions to this Subpart are promulgated at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60 Subpart Ja. The relevant requirements in 40 CFR Part 60 Subpart J include, but are not limited to the following:

Standard for Particulate Matter (60.102)

45.1 No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator (60.102(a)):

45.1.1 Particulate matter in excess of 1.0 kg/1000 kg (2.0 lb/ton [or 1.0 lb/1000 lb]) of coke burn-off in the catalyst regenerator. (60.102(a)(1))

45.1.2 Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period. (60.102(a)(2))

Standard for Carbon Monoxide (60.103)

45.2 No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis). (60.103)(a))

Standards for Sulfur Oxides (60.104)

45.3 No owner or operator subject to the provisions of this subpart shall (60.104(a)):

45.3.1 Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). 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. (60.104(a)(1))

45.3.2 Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of (60.104(a)(2)):

45.3.2.1 For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (60.104(a)(2)(i))

Monitoring of emissions and operations (60.105)

45.4 Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows: (60.105(a))

45.4.1 For fluid catalytic cracking unit catalyst regenerators subject to §60.102(a)(2) (Condition 45.1.2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity. (60.105(a)(1))

45.4.2 For fluid catalytic cracking unit catalyst regenerators subject to §60.103(a) (Condition 45.2), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2)(ii) of this section. (60.105(a)(2))

45.4.2.1 The span value for this instrument is 1,000 ppm CO. (60.105(a)(2)(i))

45.4.3 Instead of the SO_2 monitor in 60.105(a)(3) for fuel gas combustion devices subject to §60.104(a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device. (60.105(a)(4)) The H_2S monitoring device shall meet the requirements in §60.105(a)(4)(i) through (iii).

45.4.3.1 Exemptions from Monitoring: The owner or operator of a fuel gas combustion device is not required to comply with 60.105(a)(3) or (4) for fuel gas streams that are exempt under §60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in 60.105(a)(4)(iv)(A) through (D) will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under §60.104(a)(1) or it no longer meets one of the requirements in 60.105(a)(4)(iv)(A) through (D), the owner or operator must begin continuous monitoring under 60.105(a)(3) or (4) within 15 days of the change. (60.105(a)(4)(iv))

a. The following fuel gas streams are exempt from the sulfur monitoring requirements as specified in 60.105(a)(4)(iv)(C) because they are intolerant of sulfur: PSA purge gas to the hydrogen plant reforming furnace, hydrogen plant bypass line to the main plant flare and No. 1 catalyst polymerization unit purge line (prior to catalyst change out) to the main plant flare.

b. The following fuel gas streams are exempt from the sulfur monitoring requirements as specified in 60.105(a)(4)(iv)(D): recovered rail rack loading vapors (exemption application submitted on October 13, 2010).

45.4.4 For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to §60.104(a)(2)(i) (Condition 45.3.2.1), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air. (60.105(a)(5)) The continuous monitoring system shall meet the requirements in 60.105(a)(5)(i) and (ii).

45.4.5 An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1) that is not specifically exempted in §60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in 60.105(a)(3) and (4) until there are changes in operating conditions or stream composition. (60.105(b))

45.4.5.1 The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the information in 60.105(b)(1)(i) through (v). (60.105(b)(1))

45.4.5.2 The effective date of the exemption is the date of submission of the information required in 60.105(b)(1). (60.105(b)(2))

45.4.5.3 No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in 60.105(b)(3)(i), (b)(3)(ii), or (b)(3)(iii). (60.105(b)(3))

45.5 The average coke burn-off rate (thousands of kilograms per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to §60.102, §60.103, or §60.104(b)(2) (Conditions 45.1 and 45.2). (60.105(c))

45.6 For the purpose of reports under §60.7(c), periods of excess emissions shall be determined and reported are defined as follows (60.105(e)):

45.6.1 *Opacity.* All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under §60.105(a)(1) exceeds 30 percent. (60.105(e)(1))

45.6.2 *Carbon Monoxide.* All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §60.105(a)(2) exceeds 500 ppm. (60.105(e)(2))

45.6.3 *Sulfur dioxide from fuel gas combustion.* All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under §60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf). (60.105(e)(3)(ii))

Note that the preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

45.6.4 *Sulfur dioxide from Claus sulfur recovery plants.* All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air). (60.105(e)(4)(i))

Reporting and recordkeeping requirements (60.107)

45.7 For each fuel gas stream combusted in a fuel gas combustion device subject to §60.104(a)(1), if an owner or operator determines that one of the exemptions listed in §60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in §60.105(a)(4)(iv)(D) (fuel gas streams specified in Condition 45.4.3.1.b), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application. (60.107(e))

45.8 The owner or operator of an affected facility shall submit the reports required under this subpart to the Division semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. (60.107(e))

45.9 The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report. (60.107(f))

Subsequent Performance Test Requirements

45.10 Compliance with the particulate matter requirements in 60.102(a)(1) (Condition 45.1.1) shall be monitored by conducting annual performance tests as required by Condition 22.9.1.1.

46. 40 CFR Part 60 Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007

These provisions apply to the following modified equipment H-1716, H-1717, the plant 1 main flare (P1) and the asphalt unit flare (F2). These provisions also apply to the remediation equipment (AIRS pt 615) thermal oxidizer (TO-SUN-2), H-2410, the GBR unit flare (F3) and the Plant 1 rail rack VCU.

The requirements below reflect the current rule language as of the latest revisions to 40 CFR Part 60 Subpart Ja published in the Federal Register on July 13, 2016. However, if revisions to this Subpart are promulgated at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60 Subpart Ja. The relevant requirements in 40 CFR Part 60 Subpart Ja include, but are not limited to the following:

Emission Limitations (60.102a)

46.1 Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in 60.102a(g)(1) and (2). (60.102a(g))

Except as provided in 60.102a(g)(1)(iii) (Condition 46.1.2), for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in 60.102a(g)(1)(i) or the fuel gas concentration limit in 60.102a(g)(1)(ii) (Condition 46.1.1). For CO boilers or furnaces that are part of a fluid catalytic cracking unit or fluid coking unit affected facility, the owner or operator shall comply with the fuel gas concentration limit in 60.102a(g)(1)(ii) for all fuel gas streams combusted in these units. (60.102a(g)(1))

46.1.1 The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. (60.102a(g)(1)(ii))

46.1.2 The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in 60.102a(g)(1)(i) and (ii) (Condition 46.1.1). (60.102a(g)(1)(iii))

46.1.3 For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in 60.102a(g)(2)(i) through (iv). (60.102a(g)(2))

The NO_X limits apply to heaters H-1716 and H-2410.

46.1.3.1 For each natural draft process heater, comply with the limit in either 60.102a(g)(2)(i)(A) or (B). The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in 60.102a(g)(2)(i)(A). (60.102a(g)(2)(i))

a. 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis (60.102a(g)(2)(i)(A)).

The source has indicated that they will comply with the concentration limit, therefore, the mass limit in (g)(2)(i)(B) has not been included.

Design, equipment, work practice or operational standards (60.103a)

46.2 Except as provided in 60.103a(g), each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in 60.103a(b). The flare management plan must include the information described in 60.103a(a)(1) through (7). (60.103a(a))

46.3 Except as provided in 60.103a(g), each owner or operator required to develop and implement a written flare management plan as described in 60.103a(a) (Condition 46.2) must submit the plan to the Administrator as described in 60.103a(b)(1) through (3). (60.103a(b))

46.4 Except as provided in 60.103a(f) and (g) (Condition 46.7), each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in 60.103a(c)(1) through (3). (60.103a(c))

46.4.1 For a flare: (60.103a(c)(1))

46.4.1.1 Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period (60.103a(c)(a)(i)); or

46.4.1.2 Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period. (60.103a(c)(a)(ii)); or

46.4.1.3 If the monitoring alternative in §60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in 60.103a(a)(3)(vii)(C). (60.103a(c)(a)(iii))

46.4.2 For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in §60.102a(g)(1) (Condition 46.1.1) if the SO_2 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. (60.103a(c)(2))

46.5 Except as provided in 60.103a(f) and (g) (Condition 46.7), 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 60.103a(c)(1) through (3) (Condition 46.4.1 and 46.4.2). Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 60.103a(d)(1) through (5). (60.103a(d))

46.6 Except as provided in 60.103a(f) and (g) (Condition 46.7), each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to 60.103a(d) (Condition 46.5) in accordance with the applicable requirements in 60.103a(e)(1) through (3). (60.103a(e))

46.7 Modified flares shall comply with the requirements of 60.103a(c) through (e) (Conditions 46.4 through 46.6) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of 60.103a(h) (Condition 46.8) and the requirements of §60.107a(a)(2) (Condition 46.14) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of 60.103a(h) (Condition 46.8) and the requirements of §60.107a(a)(2) (Condition 46.14) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of 60.103a(h) (Condition 46.8) and the requirements of §60.107a(a)(2) (Condition 46.14) by no later than November 11, 2015. (60.103a(f))

46.8 Each owner or operator shall not burn in any affected flare any fuel gas that contains H_2S 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. (60.103a(h))

Performance Tests (60.104a)

46.9 The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in §60.102a and conduct a performance test for each flare to demonstrate initial compliance with the H_2S concentration requirement in §60.103a(h) according to the requirements of §60.8. The notification requirements of §60.8(d) apply to the initial performance test and to subsequent performance tests required by 60.104a(b) (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. (60.104a(a))

46.10 In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A-1 through A-8 or other methods as specified in this section, except as provided in §60.8(b). (60.104a(c))

46.11 The owner or operator shall determine compliance with the SO_2 and NO_X emissions limits in §60.102a(g) for a fuel gas combustion device according to the test methods and procedures in 60.104a(i).

46.12 The owner or operator shall determine compliance with the applicable H_2S emissions limit in §60.102a(g)(1) (Condition 46.1.1) for a fuel gas combustion device or the concentration requirement in §60.103a(h) (Condition 46.8) for a flare according to the test methods and procedures in 60.104a(j).

Monitoring of emissions and operations for fuel gas combustion devices and flares (60.107a)

46.13 *Fuel gas combustion devices subject to* SO_2 or H_2S *limit and flares subject to* H_2S *concentration requirements.* The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the SO_2 emission limits in §60.102a(g)(1)(i) shall comply with the requirements in 60.107a(a)(1). The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) (Condition 46.1.1) or a flare that is subject to the H_2S concentration requirement in §60.103a(h) (Condition 46.8) shall comply with 60.107a(a)(2) (Condition 46.14). (60.107a(a))

46.14 The owner or operator of a fuel gas combustion device that elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in §60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare. (60.107a(a)(2)) The H_2S monitor shall meet the requirements in 60.107a(a)(2)(i) through (iv).

46.14.1 The owner or operator of a flare subject to §60.103a(c) through (e) (Conditions 46.4 through 46.6) may use the instrument required in 60.107a(e)(1) (Condition 46.19.1) to demonstrate compliance with the H_2S concentration requirement in §60.103a(h) (Condition 46.8) if the owner or operator complies with the requirements of 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 60.107a(e)(1) (Condition 46.19.1) is used to demonstrate compliance with the H_2S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in §60.103a(h) (Condition 46.8). (60.107a(a)(2)(v))

46.14.2 The owner or operator of modified flare that meets all three criteria in 60.107a(a)(2)(vi)(A) through (C) shall comply with the requirements of 60.107a(a)(2)(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

§60.13(i) until the flare is in compliance with requirements of 60.107a(a)(2)(i) through (v). (60.107a(2)(vi))

46.15 The owner or operator of a fuel gas combustion device or flare is not required to comply with 60.107a(a)(1) or (2) (Condition 46.14) for fuel gas streams that are exempt under §§60.102a(g)(1)(iii) (Condition 46.1.2) or 60.103a(h) (Condition 46.8) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in 60.107a(a)(3)(i) through (iv) will be considered inherently low in sulfur content. (60.107a(a)(3))

The GBR flare (F3) is exempt from the monitoring requirements in Condition 46.14 because the fuel gas streams meet the requirements in 60.107a(a)(3)(i) (pilot gas) or 60.107a(a)(3)(iii) (fuel gas streams produced in process units that are intolerant to sulfur). Flare F3 only serves the GBR unit and sulfur can contaminate/poison the catalyst. In addition, the GBR unit feed streams are from the reformers and the H_2 plant, both of which are specifically listed as process units producing fuel gas streams intolerant to sulfur in 60.107a(a)(3)(iii).

TO-SUN-2 and the Plant 1 rail rack VCU are exempt from the monitoring requirements in Condition 46.14 because the fuel gas streams combusted by these units meet the requirements in 60.107a(a)(3)(iv) (fuel gas stream that an owner or operate demonstrates is low in sulfur according to 60.107a(b)). Exemption applications meeting the requirements in 60.107a(b) (Condition 46.17) were submitted on April 18, 2014 (TO-SUN-2) and September 5, 2018 (Plant 1 rail rack VCU).

46.16 If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in 60.107a(b)(3) (Condition 46.17.3). (60.107a(a)(4))

46.17 *Exemption from H_2S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H_2S monitoring requirements 60.107a(a)(2) (Condition 46.14) for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of 60.107a(a)(1) and (2) (Condition 46.14) until there are changes in operating conditions or stream composition. (60.107a(b))

46.17.1 The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the information in 60.107a(b)(3)(i) through (v). (60.107a(b)(1))

46.17.2 The effective date of the exemption is the date of submission of the information required in 60.107a(b)(1) (Condition 46.17.1). (60.107a(b)(2))

46.17.3 No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in 60.107a(b)(3)(i), (b)(3)(ii), or (b)(3)(iii). (60.107a(b)(3))

46.18 The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_X emissions (*i.e.*, low-NO_X burners, ultra-low-NO_X burners) may elect to comply with the monitoring requirements in 60.107a(c)(1) through (5) (NO_X CEMs) or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O_2 monitoring requirements in 60.107a(c)(3) through (5) to demonstrate compliance. If an O_2 operating curve is used (*i.e.*, if different O_2 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 60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively. (60.107a(c))

The source is relying on NO_X CEMS to monitor compliance with the NO_X ppm limit for heater H-1716 and H-2410. The NO_X CEMS shall meet the requirements in 60.107a(c)(1) through (5).

46.19 *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in 60.107a(e)(4) and (h) (Condition 46.19.4), the owner or operator of an affected flare subject to §60.103a(c) through (e) (Conditions 46.4 through 46.6) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with 60.107a (e)(1), (e)(2) or (e)(3) (Conditions 46.19.1 through 46.19.3). Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either 60.107a(e)(1), (e)(2) or (e)(3) (Conditions 46.19.1 through 46.19.3), the owner or operator of a modified flare must comply with the requirements related to either 60.107a (e)(1), (e)(2) or (e)(3) (Conditions 46.19.1 through 46.19.3) upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either 60.107a(e)(1), (e)(2) or (e)(3) (Conditions 46.19.1 through 46.19.3), the owner or operator of a modified flare must comply with the requirements related to either 60.107a(e)(1), (e)(2) or (e)(3) (Conditions 46.19.1 through 46.19.3) no later than November 11, 2015 or upon startup of the modified flare, whichever is later. (60.107a(e))

46.19.1 *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument or instruments for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare. (60.107a(e)(1)) The monitoring devices shall meet the requirements in 60.107a(e)(1)(i) through (iii).

46.19.2 *H_2S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument or instruments for continuously monitoring and recording the concentration of H_2S in gas discharged to the flare according to the requirements in 60.107a(e)(2)(i) through (iii) and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in 60.107a(e)(2)(iv) through (ix). (60.107a(e)(2))

46.19.3 *SO_2 monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of SO_2 from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in 60.107a(a)(1), determine the F factor of the fuel gas at least daily according to the requirements in 60.107a(d)(2) through (4), determine the higher heating value of the fuel gas at least daily according to the requirements in 60.107a(d)(7), and calculate the total sulfur content (as SO_2) in the fuel gas using Equation 15 of 60.107a. (60.107a(e)(3))

46.19.4 *Exemptions from sulfur monitoring requirements.* Flares identified in 60.107a(e)(4)(i) through (iv) are exempt from the requirements in 60.107a(e)(1) through (3) (Conditions 46.19.1 through 46.19.3). For each such flare, except as provided in 60.107a(e)(4)(iv), engineering calculations shall be used to calculate the SO_2 emissions in the event of a discharge that may trigger a root cause analysis under §60.103a(c)(1) (Condition 46.4.1). (60.107a(e)(4))

The GBR unit flare (F3) is exempt from the sulfur monitoring requirements per 60.107a(e)(4)(i)(A) (as indicated in Condition 46.15 the, the fuel gas streams fed to the GBR flare (F3) are inherently low in sulfur under 60.107(a)(3)).

46.20 *Flow monitoring for flares.* Except as provided in 60.107a(f)(2) and (h), the owner or operator of an affected flare subject to §60.103a(c) through (e) (Conditions 46.4 through 46.6) shall install, operate, calibrate and maintain, in accordance with the specifications in 60.107a(f)(1), a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later. (60.107a(f))

46.21 *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in §60.102a(g) (Condition 46.1) and flares subject to the concentration requirement in §60.103a(h) (Condition 46.8) are defined as specified in 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). (60.107a(i))

The GBR unit flare (F3) is not subject to sulfur monitoring requirements, thus the excess emission requirements for flares do not apply to this unit.

46.21.1 *SO_2 or H_2S limits for fuel gas combustion devices.* If the owner or operator of a fuel gas combustion device elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) (Condition 46.1.1), each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under 60.107a(a)(2) (Condition 46.14) exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H_2S

continuous monitoring system under 60.107a((a)(2) (Condition 46.14) exceeds 60 ppmv. (60.107a(i)(1)(ii))

46.21.2 *H_2S concentration limits for flares.*

46.21.2.1 Each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under 60.107a(a)(2) (Condition 46.14) exceeds 162 ppmv. (60.107a(i)(2)(i))

46.21.2.2 If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in 60.107a(b)(3)(iii), each day during which the daily concentration of H_2S exceeds 162 ppmv. (60.107a(i)(2)(ii))

46.21.3 *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 60.107a(c) or (d) exceeds 40 ppmv for a natural draft process heater. (60.107a(i)(3)(i)) These requirements apply to sources using a NO_X CEMS to monitor compliance with NO_X emission limitation.

46.21.4 *Daily O_2 limits for fuel gas combustion devices.* Each day during which the concentration of O_2 as measured by the O_2 continuous monitoring system required under 60.107a(c)(6) or (d)(8) exceeds the O_2 operating limit or operating curve determined during the most recent biennial performance test. (60.107a(i)(5)) These requirements apply to sources using a continuous O_2 monitoring device to monitor compliance with the NO_X emission limitation.

Recordkeeping and reporting requirements (60.108a)

46.22 Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section. (60.108a(a))

46.23 Each owner or operator subject to an emissions limitation in §60.102a shall notify the Administrator of the specific monitoring provisions of §§60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in §60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in §60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by §60.7(a)(3). (60.108a(b))

46.24 The owner of operator shall maintain the records in 60.108a(c)(1), (5), (6) and (7) (if applicable).

46.25 Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in 60.108a(d)(1) through (7). (60.108a(d))

47. 40 CFR Part 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

F102, F103, F104, F105, F106, F108, F109, F110, F111, F112, F113, F114, F115, F116, F200, F202, F205, F206, F207, F208, F209, F210, and F017 (unpermitted) components that meet the applicability criteria in §60.590a are subject to these requirements.

The definition of "process unit" in NSPS Subpart GGGa has been stayed (see 60.590a(e) and 73 FR 31376, June 2, 2008). While the definition of "process unit" is stayed owners or operations shall use the definition of "process unit" in §60.590a(e) in Subpart GGGa.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60 Subpart GGGa published in the Federal Register on June 2, 2008. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60, Subpart GGGa. The relevant requirements in 40 CFR Part 60 Subpart GGGa include, but are not limited to the following:

Standards (60.592a)

47.1 Each owner or operator subject to the provisions of this subpart shall comply with the requirements of 40 CFR Part 60 Subpart VVa §§60.482–1a to 60.482–10a as soon as practicable, but no later than 180 days after initial startup. (60.592a(a)) The subpart VVa provisions are included in Condition 55 of this permit.

47.2 For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of §60.592a as an alternative to the requirements in 40 CFR Part 60 Subpart VVa §60.482–7a. (60.592a(b))

47.3 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 §60.484a. (60.592a(c))

47.4 Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 40 CFR Part 60 Subpart VVa §60.485a except as provided in §60.593a. (60.592a(d))

47.5 Each owner or operator subject to the provisions of this subpart shall comply with the provisions of 40 CFR Part 60 Subpart VVa §§60.486a and 60.487a. (60.592a(e))

Exceptions (60.593a)

47.6 Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VVa of this part. 60.593a(a))

47.7 Compressors in hydrogen service are exempt from the requirements of §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service. (60.593a(b)(1) The provisions in 60.593a(b)(2) or (b)(3) shall be used to demonstrate that the compressor is in hydrogen service.

47.8 Any existing reciprocating compressor that becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §60.482-3a(a), (b), (c), (d), (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 §60.482-3a(a), (b), (c), (d), (e), and (h). (60.593a(c))

47.9 An owner or operator may use the following provision in addition to §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 §60.17). (60.593a(d))

47.10 Open-ended valves or lines containing asphalt as defined in §60.591a are exempt from the requirements of §60.482-6a(a) through (c). (60.593a(f))

47.11 Connectors in gas/vapor or light liquid service are exempt from the requirements in §60.482-11a, provided the owner or operator complies with §60.482-8a for all connectors, not just those in heavy liquid service. (60.593a(g))

48. 40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984

D-20, T34, T55, T60, T96, T97, T116, T775, T2010, T4501, T4504, T4514, T4515, T4516, T4517, T4518 and T7208 are subject to these requirements.

Tank D-20 has is not subject to the standards in 60.112b (design capacity greater than 75 m^3 and less than 151 m^3 and stores a VOL with a maximum true vapor pressure less than 27.6 kPa and is only subject to the monitoring requirements in 60.116b, except for 60.116b(g) (Condition 48.18).

The requirements below reflect the current rule language as of the latest revisions to 40 CFR Part 60 Subpart Kb published in the Federal Register on January 19, 2021. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60, Subpart Kb. The relevant requirements in 40 CFR Part 63 Subpart Kb include, but are not limited to the following:

Applicability (60.110b)

48.1 *Option to comply with part 63, subpart WW, of this chapter.* Except as specified in 60.110b(e)(5)(i) through (iv), owners or operators may choose to comply with 40 CFR part 63, subpart WW, to satisfy the requirements of §§60.112b through 60.117b for storage vessels either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa, or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa. (60.110b(e)(5))

Standards (60.112b)

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

48.2.1 A fixed roof in combination with an internal floating roof meeting the specifications in 60.112b(a)(1). Tanks T96, T97, T116 and T7208 meet the NSPS Kb requirements with this option.

48.2.2 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 specifications in 60.112b(a)(2). Tanks T34, T55, T60, T775, T2010 and T4501 meet the NSPS Kb requirements with this option.

48.2.3 A closed vent system and control device meeting the specifications in 60.112b(a)(3). T4504, T4514, T4515, T4516, T4517 and T4518 meet the NSPS Kb requirements with this option.

48.3 The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 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 (60.112b(b)):

48.3.1 A closed vent system and control device as specified in §60.112b(a)(3). (60.112b(b)(1))

48.3.2 A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart. (60.112b(b)(2))

Testing and procedures (60.113b)

48.4 The owner or operator of each storage vessel as specified in §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 §60.112b.

48.5 After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall (60.113b(a)):

48.5.1 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. (60.113b(a)(1))

48.5.2 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 §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. (60.113b(a)(2))

48.5.3 For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B) (60.113b(a)(3)):

48.5.3.1 Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years (60.113b(a)(3)(i)); or

48.5.3.2 Visually inspect the vessel as specified in paragraph (a)(2) of this section. (60.113b(a)(3)(ii))

48.5.4 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. (60.113b(a)(4))

48.5.5 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. (60.113b(a)(5))

48.6 After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall (60.113b(b)):

48.6.1 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 frequency in 60.113b(b)(1)(i) through (iii). (60.113b(b)(1))

48.6.2 Determine gap widths and areas in the primary and secondary seals individually by the following the procedures in 60.113b(b)(2).

48.6.3 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 60113b(b)(4). (60.113b(b)(3))

48.6.4 Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 60.113b(b)(4)(i) and (ii).

48.6.5 Notify the Administrator 30 days in advance of any gap measurements required by 60113b(b)(1) to afford the Administrator the opportunity to have an observer present. (60.113b(b)(5))

48.6.6 Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed. (60.113b(b)(6))

48.6.6.1 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. (60.113b(b)(6)(i))

48.6.6.2 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. (60.113b(b)(6)(ii))

48.7 The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements. (60.113b(c))

48.7.1 Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed in 60.113b(c)((1)(i) and (ii). (60.113b(c)(1))

48.7.2 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. (60.113b(c)(2))

Reporting and recordkeeping requirements (60.115b)

48.8 The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by 60.115b(a), (b), or (c) depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment. In lieu of retaining records for 2 years, records shall be kept for 5 years as specified in Section IV, Condition 22.

48.9 After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the recordkeeping and reporting requirements in 60.11b(a)(1) through (4). (60.115b(a))

48.10 After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the recordkeeping and reporting requirements in 60.115b(b)(1) through (4). (60.115b(b))

48.11 After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the records specified in 60.115b(c)(1) and (2). (60.115b(c))

Monitoring of operations (60.116b)

48.12 The owner or operator shall keep copies of all records required by this section, 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. (60.116b(a)) In lieu of retaining records for 2 years, records shall be kept for 5 years as specified in Section IV, Condition 22.

48.13 The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. (60.116b(b)) As required by 60.116b(a), these records shall be kept for the life of the source.

48.14 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 m^3 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 m^3 but less than 151 m^3 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. (60.116b(c))

48.15 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 m^3 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 m^3 but less than 151 m^3 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. (60.116b(d))

48.16 Available data on the storage temperature may be used to determine the maximum true vapor pressure as specified in 60.116b(e)(1) through (3).

48.17 The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the requirements in 60.116b(f)(1) and (2).

48.18 The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §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 60.116b(c) and (d). (60.16b(g))

49. 40 CFR Part 60, Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

T2006, and T3201 are subject to these requirements, however, current operations do not include still blowing that could result in opacity emissions. In the absence of conducting any still blowing, and in the absence of credible evidence to the contrary, the sources are presumed to be in compliance with the provisions of 40 CFR, Part 60, Subpart UU.

The requirements below reflect the rule language in 40 CFR Part 60 Subpart UU as of the latest revisions to 40 CFR Part 60 Subpart UU published in the Federal Register on February 27, 2014. However, the permittee is subject to the latest version of 40 CFR Part 60 Subpart UU. The relevant requirements in 40 CFR Part 60 Subpart UU include, but are not limited to the following:

49.1 No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any asphalt storage tank exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. The control device shall not be by-passed during this 15-minute period. (60.472(c))

Monitoring of Operations

49.2 Method 9 and the procedures in 60.11 shall be used to determine opacity. (60.474(c)(5))

49.2.1 If still blowing were to take place during periods when the transfer lines are being blown, the permittee shall perform a visual inspection of the source stack. Such inspection shall last at least fifteen minutes. When visible emissions persist for more than fifteen (15) minutes, an EPA Reference Method 9 observation shall be performed within one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

49.2.2 Records of the results of EPA Reference Method 9 readings and a copy of the EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division upon request. Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled report.

50. 40 CFR Part 60, Subpart XX – Standards of Performance for Bulk Gasoline Terminals

The requirements of this subpart are solely applicable to delivery of liquid products into gasoline tank trucks, and do not apply to the loading of products into non-gasoline tank trucks.

R102 is subject to these requirements.

R101 is not directly subject to these requirements but it is subject to some of these requirements as specified in 40 CFR Part 63 Subpart R (Condition 52).

The requirements below reflect the rule language in 40 CFR Part 60 Subpart XX as of the latest revisions to 40 CFR Part 60 Subpart XX published in the Federal Register on December 19, 2003. However, the permittee is subject to the latest version of 40 CFR Part 60 Subpart XX. The relevant requirements in 40 CFR Part 60 Subpart XX include, but are not limited to the following:

Standard for Volatile Organic Compound (VOC) emissions from bulk gasoline terminals (60.502)

The owner or operator of each bulk gasoline terminal containing an affected facility shall comply with the requirements of this section.

50.1 Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compound vapors displaced from tank trucks during product loading. (60.502(a))

50.2 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 60.502(c). (60.502(b))

50.3 Each vapor collection system shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack. (60.502(d))

50.4 Loading of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the procedures set forth in 60.502(e).

50.5 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. (60.502(f))

50.6 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. (60.502(g))

50.7 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). (60.502(h))

50.8 No pressure-vacuum vent in the bulk gasoline terminal's vapor collection system shall begin to open at a system pressure less than 4,500 pascals (450 mm of water). (60.502(i))

50.9 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 purpose 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. (60.502(j))

Test Methods and Procedures (60.503)

50.10 In conducting the performance tests required in § 60.8, the owner or operator 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 § 60.8(b). The three-run requirement of § 60.8(f) does not apply to this subpart. (60.503(a))

50.11 Immediately before the performance test required to determine compliance with § 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. (60.503(b))

50.12 The owner or operator shall determine compliance with the standards in § 60.502(b) and (c) in accordance with the procedures in 60.503(c)(1) through (7). (60.503(c))

50.13 The owner or operator shall determine compliance with the standard in § 60.502(h) in accordance with the procedures in 60.503(d)(1) and (2). (60.503(d))

50.14 The performance test requirements of paragraph (c) of this section do not apply to flares defined in §60.501 and meeting the requirements in §60.18(b) through (f). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in §§60.18(b) through (f) and 60.503(a), (b), and (d). (60.503(e))

Reporting and Recordkeeping (60.505)

50.15 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. (60.505(a))

50.16 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 information set forth in 60.505(b).

50.17 A record of each monthly leak inspection required under 60.502(j) shall be kept on file at the terminal for at least 5 years. Inspection records shall include, as a minimum, the information set forth in 60.505(c). (60.505(c), revised to reflect the requirement to maintain records for 5 years under the operating permit program.)

50.18 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 5 years. (60.505(d), revised to reflect the requirement to maintain records for 5 years under the operating permit program.)

50.19 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 5 years. (60.505(f), revised to reflect the requirement to maintain records for 5 years under the operating permit program.)

51. Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems – 40 CFR Part 60, Subpart QQQ

The CPI Separator (F101 - Asphalt Unit Sewer System) is subject to the requirements for oil-water separators.

The individual drain systems associated with F101, F103, F104, F109, F110, F113, F114 and F204 are subject to the requirements for individual drain systems.

As specified in 40 CFR Part 63 Subpart CC §63.640(o)(1) specifies that a Group 1 wastewater stream managed in a piece of equipment that is also subject the provisions of 40 CFR Part 60 Subpart QQQ is only required to comply with 40 CFR Part 63 Subpart CC. T4514 and T4515 fall under this provision – they need only comply with the provisions of 40 CFR Part 63 Subpart CC.

The requirements below reflect the rule language in 40 CFR Part 60 Subpart QQQ as of the latest revisions to 40 CFR Part 60 Subpart QQQ published in the Federal Register on October 17, 2000. However, the permittee is subject to the latest version of 40 CFR Part 60 Subpart QQQ. The relevant requirements in 40 CFR Part 60 Subpart QQQ include, but are not limited to the following:

Standards: General (60.692-1)

51.1 Each owner of operator subject to the provisions of this subpart shall comply with the requirements of 60.692-1 to 60.692-5 and with 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction. (60.692-1(a))

51.2 Compliance with 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. (60.692-1(b))

Standards: Individual drain systems (60.692-2)

51.3 Each drain shall be equipped with water seal controls. (60.692-2(a)(1))

51.4 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. (60.692-2(a)(2))

51.5 Except as provided in 60.692-2(a)(4), 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.(60.692-2(a)(3))

51.6 As an alternative to the requirements in 60.692(a)(3), if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed. (60.692-2(a)(4))

51.7 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 60.692-6. (60.692-2(a)(5))

51.8 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. (60.692-2(b)(1))

51.9 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. (60.692-2(b)(2))

51.10 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. (60.692-2(b)(3))

51.11 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 60.692-6. (60.692-2(b)(4))

51.12 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. (60.692-2(c)(1))

51.13 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. (60.692-2(c)(2))

51.14 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 60.692-6. (60.692-2(c)(3))

51.15 Except as provided in 60.692-2(e), 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. (60.692-2(d))

51.16 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. (60.692-2(e))

Standards: Oil-water separators (60.692-3)

51.17 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 specifications set forth in 60.692-3(a), except as provided in 60.692-3(d) or in 60.693-2. (60.692-3(a))

51.17.1 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. (60.692-3(a)(1))

51.17.2 The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device. (60.692-3(a)(2))

51.17.3 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. (60.692-3(a)(3))

51.17.4 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. (60.692-3(a)(4))

51.17.5 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 §60.692–6. (60.692-3(a)(5))

51.18 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 this subpart. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of 60.692-3(a). (60.692-3(e))

51.19 Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with 60.692-3(a), and not 60.692-3(b), 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. (60.692-3(f))

Standards: Delay of repair (60.692-6)

51.20 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. (60.692-6(a))

51.21 Repair of such equipment shall occur before the end of the next refinery or process unit shutdown. (60.692-6(b))

Recordkeeping requirements (60.697)

51.22 Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements set forth in 60.697, as applicable. All records shall be retained for a period of 5 years after being recorded unless otherwise noted. (60.697(a), revised to require record retention of five years, for operating permit purposes.)

Reporting Requirements (60.698)

51.23 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 to the Division. (60.698(c))

52. 40 CFR Part 63, Subpart R – National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

R102 are subject to these requirements.

The requirements below reflect the rule language in 40 CFR Part 63 Subpart R as of the latest revisions to 40 CFR Part 63 Subpart R published in the Federal Register on November 19, 2020. However, the permittee is subject to the latest version of 40 CFR Part 63 Subpart R. The relevant requirements in 40 CFR Part 63 Subpart R include, but are not limited to the following:

52.1 Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart that is also subject to applicable provisions of 40 CFR Part 60, Subpart Kb or XX shall comply only with the provisions in each Subpart that contain the most stringent control requirements for that facility. (63.420(g))

52.2 Each owner or operator of an affected source bulk gasoline terminal or pipeline breakout station is subject to the provisions of 40 CFR Part 63, Subpart A – General Provisions, as indicated in Table 1 of Subpart R. (63.420(h)) These requirements include, but are not limited to the following:

52.2.1 Prohibited activities in §63.4.

52.2.2 Operation and maintenance requirement in §63.6(e)(1).

52.2.3 Startup, shutdown and malfunction plant requirements in §63.6(e)(3).

52.2.4 Performance test requirements in §63.7.

52.2.5 Monitoring requirements in §63.8.

52.2.6 Notification requirements in §63.9.

52.2.7 Recordkeeping requirements in §63.10.

52.2.8 Control device and work practice requirements in §§63.11(b) and (c).

Standards: Loading Racks (63.422)

52.3 Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in 40 CFR Part 60, Subpart XX, 60.502 (see Condition 50 of this permit) except for paragraphs (b), (c), and (j) of that section. (63.422(a))

52.4 Emissions to the atmosphere from the vapor collection and processing systems due to the loading of gasoline cargo tanks shall not exceed 10 milligrams of total organic compounds per liter of gasoline loaded. (63.422(b))

52.5 Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall comply with 40 CFR Part 60, Subpart XX, 60.502(e) as follows:

52.5.1 For the purposes of this section, the term "tank truck" as used in §60.502(e) of this chapter means "cargo tank." (63.422(c)(1))

52.5.2 Section 60.502(e)(5) of this chapter is changed to read: The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline cargo tank will not be reloaded at the facility until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

52.5.2.1 The tank truck or railcar gasoline cargo tank meets the test requirements in §63.425(e), or the railcar gasoline cargo tank meets applicable test requirements in §63.425(i);

52.5.2.2 For each gasoline cargo tank failing the test in §63.425 (f) or (g) at the facility, the cargo tank meets the requirements in either 63.422(c)(ii)(A) or (B). (63.422(c)(2))

Standards: Equipment Leaks (63.424)

52.6 Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to this subpart shall perform a monthly leak inspection of all equipment in gasoline service. For this inspection, detection methods incorporating sight, sound, and smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank. (63.424(a))

52.7 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 shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility. (63.424(b))

52.8 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 63.424(d). (63.424(c))

52.9 Owners and operators shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to the methods listed in 63.424(g).

Test Methods and Procedures (63.425)

52.10 Each owner or operator subject to the emission standard in § 63.422(b) or 40 CFR 60.112b(a)(3)(ii) shall comply with the requirements in 63.425(a)(1) and (2). (63.425(a))

52.10.1 Conduct a performance test on the vapor processing and collection systems according to either 60.425(a)(1)(i) or (ii). (63.425(a))

52.10.1.1 Use the test methods and procedures in 40 CFR 60.503 of this chapter, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under 40 CFR 60.503(b) (63.425(a)(1)(i)), or

52.10.1.2 Use alternative test methods and procedures in accordance with the alternative test method requirements in § 63.7(f). (63.425(a)(1)(ii))

52.10.2 The performance test requirements of 40 CFR 60.503(c) do not apply to flares defined in § 63.421 and meeting the flare requirements in § 63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in § 63.11(b) and 40 CFR 60.503(a), (b) and (d), respectively. (63.425(a)(2))

52.11 For each performance test conducted under 63.425(a), the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure (63.425(b)):

52.11.1 During the performance test, continuously record the operating parameter under § 63.427(a) (63.425(b)(1));

52.11.2 Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations (63.425(b)(2)); and

52.11.3 Provide for the Administrator’s approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in § 63.422(b) or § 60.112(b)(a)(3)(ii) or this chapter. (63.425(b)(3)).

52.12 For performance tests performed after the initial test, the owner or operator shall document the reasons for any change in the operating parameter value since the previous performance test. (63.425(c))

52.13 *Annual certification test.* The annual certification test for gasoline cargo tanks shall consist of the test methods and procedures in 63.425(e)(1) and (2). (63.425(e))

52.14 *Leak detection test.* The leak detection test shall be performed using Method 21, appendix A, 40 CFR part 60, except omit section 4.3.2 of Method 21. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in 63.425(f)(1) and (2). (63.425(f))

52.15 *Nitrogen pressure decay field test* For those cargo tanks with manifolded product lines, this test procedure (63.425(g)(1) through (5)) shall be conducted on each compartment. (63.425(g))

52.16 *Continuous performance pressure decay test.* The continuous performance pressure decay test shall be performed using Method 27, appendix A, 40 CFR Part 60. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H_2O (18 in. H_2 O), gauge. The maximum allowable 5-minute pressure change (Δ p) which shall be met at any time is shown in the third column of Table 2 of §63.425(e)(1). (63.425(h)).

52.17 *Railcar bubble leak test procedures.* As an alternative to 63.425(e) for annual certification leakage testing of gasoline cargo tanks, the owner or operator may comply with 63.425(i)(1) and (2) for railcar gasoline cargo tanks, provided the railcar tank meets the requirement in 63.425(i)(3). (63.425(i))

Continuous Monitoring (63.427)

52.18 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) as specified in 63.427(a)(1), (a)(2), (a)(3), or (a)(4), except as allowed in 63.427(a)(5). (63.427(a)) Note that only options (a)(3) and (a)(4) were included as they are the only options that apply to either R101 (subject to MACT R via MACT CC) or R102.

52.18.1 Where a thermal oxidation system other than a flare is used, a CPMS capable of measuring temperature must be installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs. (63.427(a)(3))

52.18.2 Where a flare meeting the requirements in § 63.11(b) is used, a heat-sensing device, such as an ultraviolet beam sensor or a thermocouple, must be installed in proximity to the pilot light to indicate the presence of a flame.(63.427(a)(4))

52.19 Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall operate the vapor processing system in a manner not to exceed the operating parameter value for the parameter described 63.427(a)(1) and (a)(2), or to go below the operating parameter value for the parameter described in 63.427(a)(3), and established using the procedures in §63.425(b). In cases where an alternative parameter pursuant to 63.427(a)(5) 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. Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as specified above, shall constitute a violation of the emission standard in §63.422(b). (63.427(b)).

Reporting and Recordkeeping (63.428)

52.20 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 63.428(b)(1) through (3). (63.428(b))

52.21 Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall maintain the records in 63.428(c)(1) through (3). (63.428(c))

52.22 Each owner or operator complying with the provisions of 63.424(a) through (d) shall record the information set forth in 63.428(e) in the log book for each leak detected. (63.428(e))

52.23 Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual report to the Administrator the following information, as applicable ((63.428(g):

52.23.1 Each loading of a gasoline cargo tank for which vapor tightness documentation had not been previously obtained by the facility (63.428(g)(1));

52.23.2 The number of equipment leaks not repaired within 5 days after detection. (63.428(g)(3))

52.24 Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall submit an excess emissions report to the Administrator in accordance with §63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable (63.428(h)):

52.24.1 Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under §63.425(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. (63.428(h)(1))

52.24.2 Each instance of a nonvapor-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. (63.428(h)(2))

52.24.3 Each reloading of a nonvapor-tight gasoline cargo tank at the facility before vapor tightness documentation for that cargo tank is obtained by the facility in accordance with §63.422(c)(2). (63.428(h)(3))

52.24.4 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, the information in 63.428(h)(3)(i) through (iv). (63.428(h)(4))

52.25 As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in 63.428(b), an owner or operator may comply with the requirements in either 63.428(k)(1) or (2). (63.428(k))

53. 40 CFR Part 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

The requirements below reflect the current rule language as of the latest revisions to 40 CFR Part 63 Subpart CC published in the Federal Register on November 19, 2020. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63 Subpart CC.

The relevant requirements in 40 CFR Part 63 Subpart CC include, but are not limited to the following:

Applicability and designation of affected source (63.640)

53.1 This subpart applies to petroleum refining process units and to related emissions points that are specified in 63.640(c)(1) through (9) that are located at a plant site and that meet the criteria in 63.640(a)(1) and (2):

53.1.1 Are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act (63.640(a)(1)); and

53.1.2 Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart. (63.640(a)(2))

53.2 The affected source subject to this subpart does not include the emission points listed in 63.640(d)(1) through (d)(4) and the provisions of this subpart do not apply to the processes specified in 63.640(g)(1) through (g)(7). (63.640(d) and (g))

53.3 **Compliance dates.** Sources subject to this subpart are required to achieve compliance on or before the dates specified in table 11 of this subpart, except as provided in 63.640(h)(1) through (3). (63.640(h))

The facility is considered an existing source (commenced construction or reconstruction prior to July 14, 1994) and for initial requirements, the compliance date was August 18, 1998. However, with the December 1, 2015 and July 13, 2016 revisions, compliance dates for new or modified requirements were established as follows:

Requirement	Compliance Date
Miscellaneous Process Vents (MPVs): §§63.643(a) & (b), 63.644 & 63.645	On or before August 18, 1998. Note that for equipment that did not meet the definition of MPV until the December 1, 2015 revisions to 40 CFR Part 60 Subpart CC, the compliance date is February 1, 2016 (the effective date for those revisions).
Pressure Relief Devices: §63.648(j)(1) and (2)	February 1, 2016[1]
Pressure Relief Devices: §63.648(j)(3), (6) & (7)	On or before January 30, 2019
Storage Vessels: §63.660, or if applicable, §63.640(n)	Transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016.
Maintenance Vents: §63.643(c)	On or before December 26, 2018
Fence Line Monitoring: §63.658	On or before January 1, 2018
Good Operating Practices: §63.642(n)	Upon initial startup or February 1, 2016, whichever is later.
Flares as Control Device:[2] §§ 63.670 & 63.671	On or before January 30, 2019

[1]Note that Table 11 lists the compliance date for these requirements as August 18, 1998, however, the requirements in 63.648(j)(1) and (2) were not included in 40 CFR Part 63 Subpart CC until the December 1, 2015 revisions, so the compliance date is the effective date for those revisions.
[2]The compliance date for flares used as control devices was not included in Table 11 but was included here for convenience.

Note that the overlap provisions specified in 63.640(n), (o), (p), (r) and (s) are included in the equipment specific sections to which they relate.

General Standards (63.642)

53.4 The emission standards set forth in this subpart shall apply at all times. (63.642(b))

53.5 Table 6 of this subpart specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to this subpart. (603.642(b) The requirements in Table 6 that apply to this facility, include bur are not limited to the following:

53.5.1 Prohibited activities and circumvention in §63.4.

53.5.2 <u>§63.6:</u> Operation and maintenance requirements in §63.6(e)(1)(iii), compliance with non-opacity standards in §63.6(f)(2) (except the phrase "as specified in §63.7(c)" in 63.6(f)(2((iii)(D) does not apply since CC does not require a site-specific test plan) & (f)(3) (except the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.642(n) and performance test results may be written or electronic) and compliance with opacity and visible emission standards in 63.6(h)(2), (h)(6) & (h)(8) (except performance test results may be written or electronic).

53.5.3 <u>§63.7:</u> The applicability and performance test date requirements in §63.7(a)(1) thru (4) (except under (a)(2), the test results must be submitted in the notice of compliance status report due 150 days after the compliance date per 63.655(f), unless they are required to be submitted electronically in accordance with 63.655(h)(9). Test results submitted electronically must be submitted by the date the Notification of Compliance Status report is submitted.), the notification of performance test in §63.7(b) (except it is due 30 days prior to the performance test), the performance testing facilities requirement in §63.7(d) and the conduct of performance test requirements in §63.7(e)(2) thru (4).

53.5.4 <u>§63.8:</u> The applicability requirements in §63.8(a)(1) thru (4) (except that in (a)(2) for a flare complying with 63.670, the cross-reference to 63.11 does not include 63.11(b)), conduct of monitoring requirements in §63.8(b), operation and continuous monitoring system requirements in §63.8(c)(1) (excluding (c)(1)(i) and (ii)), (c)(2), (c)(3) (except that verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would monitor accurately) & (c)(4) (except that for sources other than flares, this subpart specifies the monitoring cycle frequency specified in §63.8(c)(4)(ii) is "once every hour" rather than "for each successive 15-minute period"), the performance evaluation of continuous monitoring systems requirements in §63.8(e) (except that results are to be submitted electronically if required by 63.655(h)(9)) and the use of an alternative monitoring method requirements in §63.8(f)(1) thru (3), (f)(4)(ii) & (f)(5).

53.5.5 <u>§63.10:</u> The general recordkeeping requirements in §63.10(b)(2)(vi), (viii), (ix), (x). (xii) & (xiv), the additional recordkeeping requirements for sources with continuous monitoring systems in §63.10(c)(7) & (8) and the general reporting requirements in §63.10(d)(1) & (4),

53.5.6 The control device and work practice requirements in §63.11, except that flares complying with §63.670 are not subject to the requirements of §63.11(b). Note that the requirements in 63.11(b) apply until January 30, 2019 (compliance date for flare requirements) unless the source opts to comply with the flare requirements prior to January 30, 2019 as provided for in 60.640(s) (Condition 53.87).

53.6 Initial performance tests and initial compliance determinations shall be required only as specified in this subpart. (63.642(d)). The provisions in 63.642(d)(1) through (4) shall be met.

53.7 All applicable records shall be maintained as specified in §63.655(i). (63.642(e))

53.8 All reports required under this subpart shall be sent to the Administrator at the addresses listed in §63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media. (63.642(f)) In addition, reports shall be submitted to the Division at the address provided in Appendix D of this permit.

53.9 The owner or operator of an existing source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in 63.642(g). (63.642(g))

53.10 The owner or operator of an existing source shall demonstrate compliance with the emission standard in 63.642(g) by following the procedures specified in 63.642(k) for all emission points, or by following the emissions averaging compliance approach specified in 63.642(l) for specified emission points and the procedures specified in 63.642(k)(1). (63.642(i)) Note that this facility is not following the emissions averaging compliance approach specified in 63.642(l).

53.11 The owner or operator of an existing source may comply, and the owner or operator of a new source shall comply, with the applicable provisions in §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as specified in §63.640(h). (63.640(k))

53.11.1 The owner or operator using this compliance approach shall also comply with the requirements of §§63.648 and/or 63.649, 63.654, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable. (63.642(k)(1))

53.11.2 The owner or operator using this compliance approach is not required to calculate the annual emission rate specified in 63.642(g). (63.642(k)(2))

53.12 At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements 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. (63.642(n))

Miscellaneous process vent provisions (63.643)

53.13 The owner or operator of a Group 1 miscellaneous process vent as defined in §63.641 shall comply with the requirements of either 63.643(a)(1) or (2) or, if applicable, 63.643(c). The owner or operator of a miscellaneous process vent that meets the conditions in 63.643(c) is only required to comply with the requirements of 63.643(c) and §63.655(g)(13) and (i)(12) for that vent. (63.643(a)). Note that the source is complying with the requirements in 63.643(a)(1), so only those requirements have been included.

53.13.1 Reduce emissions of organic HAP's using a flare. On and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the requirements of §63.11(b) of subpart A or the requirements of §63.670. (63.643(a)(1))

53.14 An owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent nor identify maintenance vents in a Notification of Compliance Status report. The owner or operator must comply with the applicable requirements in 63.643(c)(1) through (3) for each maintenance vent according to the compliance dates specified in table 11 of this subpart (Condition 53.3), unless an extension is requested in accordance with the provisions in §63.6(i). (63.643(c))

53.14.1 Prior to venting to the atmosphere, process liquids are removed from the equipment as much as practical and the equipment is depressured to a control device meeting requirements in 63.343(a)(1) or (2), a fuel gas system, or back to the process until one of the following conditions, as applicable, is met. (63.643(c)(1))

53.14.1.1 The vapor in the equipment served by the maintenance vent has a lower explosive limit (LEL) of less than 10 percent. (63.643(c)(1)(i))

53.14.1.2 If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent. (63.643(c)(1)(ii))

53.14.1.3 The equipment served by the maintenance vent contains less than 72 pounds of total volatile organic compounds (VOC). (63.643(c)(1)(iii))

53.14.1.4 If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.*, hydrotreaters and hydrocrackers) and a pure hydrogen supply is not available at the equipment at the time of the startup, shutdown, maintenance, or inspection activity, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent. (63.643(c)(1)(iv))

53.14.1.5 If, after applying best practices to isolate and purge equipment served by a maintenance vent, none of the applicable criterion in 63.343(c)(1)(i) through (iv) can be met prior to installing or removing a blind flange or similar equipment blind, the pressure in the equipment served by the maintenance vent is reduced to 2 psig or less. Active purging of the equipment may be used provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less. (63.643(c)(1)(v))

53.14.2 Except for maintenance vents complying with the alternative in 63.643((c)(1)(iii), the owner or operator must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications. (63.643(c)(2))

53.14.3 For maintenance vents complying with the alternative in 63.643(c)(1)(iii), the owner or operator shall determine mass of VOC in the equipment served by the maintenance vent based on the equipment size and contents after considering any contents drained or purged from the equipment. Equipment size may be determined from equipment design specifications. Equipment contents may be determined using process knowledge. (63.643(c)(3))

53.15 After February 1, 2016 and prior to the date of compliance with the maintenance vent provisions in 63.643(c), the owner or operator must comply with the requirements in §63.642(n) (Condition 53.12) for each maintenance venting event and maintain records necessary to demonstrate compliance with the requirements in §63.642(n) (Condition 53.12) including, if appropriate, records of existing standard site procedures used to deinventory equipment for safety purposes. (63.643(d))

Monitoring provisions for miscellaneous process vents (63.644)

53.16 Except as provided in 63.644(b), each owner or operator of a Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in §63.643(a) (Condition 53.13) shall install the monitoring equipment specified in 63.644(a)(1), (2), (3), or (4), depending on the type of combustion device used. All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer’s specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately and, except for CPMS installed for pilot flame monitoring, must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart. (63.644(a)) Since the source is using a flare to comply with these requirements, only the provisions in 63.644(a)(2) have been included.

53.16.1 Where a flare is used prior to January 30, 2019, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame is required, or the requirements of §63.670 shall be met. Where a flare is used on and after January 30, 2019, the requirements of §63.670 shall be met. (63.644(a)(2))

53.17 The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with 63.644(a) either directly to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a) (Condition 53.13) shall comply with either 63.644(c)(1), (2), or (3). Use of the bypass at any time to divert a Group 1 miscellaneous process vent stream to the atmosphere or to a control device that does not comply with the requirements in § 63.643(a) (Condition 53.13) is an emissions standards violation. Equipment such as low leg drains and equipment subject to § 63.648 are not subject to this 63.644(c). (63.644(c))

53.17.1 Install, calibrate and maintain a flow indicator that determines whether a vent stream flow is present at least once every hour. A manual block valve equipped with a valve position indicator may be used in lieu of a flow indicator, as long as the valve position indicator is monitored continuously. Records shall be generated as specified in §63.655(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere (63.644(c)(1)); or

53.17.2 Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the non-diverting position and that the vent stream is not diverted through the bypass line. (63.644(c)(2)); or

53.17.3 Use a cap, blind flange, plug, or a second valve for an open-ended valve or line following the requirements specified in § 60.482-6(a)(2), (b) and (c). (63.644(c)(3))

53.18 The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under 63.644(a) and (b). In order to establish the range, the information required in §63.655(f)(3) shall be submitted in the Notification of Compliance Status report. (63.644(d))

53.19 Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under 63.644(a) and (b. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.655(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart. (63.644(e))

Test methods and procedures for miscellaneous process vents (63.645)

53.20 To demonstrate compliance with §63.643, an owner or operator shall follow §63.116 except for §63.116 (a)(1), (d) and (e) of subpart G of this part except as provided in paragraphs (b) through (d) and paragraph (i) of this section. (63.645(a)) Note that since the source has indicated that they will rely on a flare to comply with the MPV requirements, only the provisions in 63.116(a) apply, so the requirements in 63.116(a), (a)(2) and (a)(3) have been included below.

53.20.1 When a flare is used to comply with §63.113(a)(1), the owner or operator shall comply with paragraphs (a)(1) through (3) of this section. The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration. (63.116(a))

53.20.1.1 Determine the net heating value of the gas being combusted using the techniques specified in §63.11(b)(6). (63.116(a)(2))

53.20.1.2 Determine the exit velocity using the techniques specified in either §63.11(b)(7)(i) (and §63.11(b)(7)(iii), where applicable) or §63.11(b)(8), as appropriate. (63.116(a)(3))

53.21 All references to §63.113(a)(1) or (a)(2) in §63.116 of subpart G of this part shall be replaced with §63.643(a)(1) or (a)(2), respectively. (63.645(b))

53.22 For purposes of determining the TOC emission rate, as specified 63.645(f), the sampling site shall be after the last product recovery device (as defined in §63.641 of this subpart) (if any recovery devices are present) but prior to the inlet of any control device (as defined in §63.641 of this subpart) that is present, prior to any dilution of the process vent stream, and prior to release to the atmosphere. (63.645(e))

53.22.1 Methods 1 or 1A of 40 CFR part 60, appendix A-1, as appropriate, shall be used for selection of the sampling site. For vents smaller than 0.10 meter in diameter, sample at the center of the vent. (63.645(e)(1))

53.22.2 No traverse site selection method is needed for vents smaller than 0.10 meter in diameter. (63.645(e)(2))

53.23 Except as provided in 63.645(g), an owner or operator seeking to demonstrate that a process vent TOC mass flow rate is less than 33 kilograms per day for an existing source or less than 6.8 kilograms per day for a new source in accordance with the Group 2 process vent definition of this subpart shall determine the TOC mass flow rate by the following procedures in 63.645(f)(1) through (5). (63.645(f))

53.24 Engineering assessment may be used to determine the TOC emission rate for the representative operating condition expected to yield the highest daily emission rate. (63.645(g)) Engineering assessments include, but are not limited to the information in 63.645(g)(1)(i) through (v).

53.25 The owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph, process changes do not include: process upsets; unintentional, temporary process changes; and changes that are within the range on which the original calculation was based. (63.645(h))

53.25.1 The TOC emission rate shall be recalculated based on measurements of vent stream flow rate and TOC as specified in 63.645(e) and (f), as applicable, or on best engineering assessment of the effects of the change. Engineering assessments shall meet the specifications in 63.645(g). (63.645(h)(1))

53.25.2 Where the recalculated TOC emission rate is greater than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in §63.655(f), (g), or (h) and shall comply with the appropriate provisions in §63.643 by the dates specified in §63.640. (63.645(h)(2))

53.26 A compliance determination for visible emissions shall be conducted within 150 days of the compliance date using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions. (63.645(i))

Storage Vessel Provisions (63.646)

All tanks addressed in Section II of this permit (listed in the table in Section I, Condition 5.1) are subject to these requirements, except as noted below.

Tanks D-811, D-812, D-813, D-814, T81, T82, T90, T91, T92 and T400 are not considered storage vessels under MACT CC because they are pressure vessels.

Tank T7208 is part of the truck rack (R102). The truck loading rack at the Suncor facility is classified under SIC 5171, and is operated by Suncor Energy (U.S.A.)'s pipeline operation, as opposed to the Refinery (SIC Code 2911), therefore the requirements in 40 CFR Part 63 Subpart CC do not apply.

Tanks 17675 and 20529 and the pipeline receipt station sump are not considered storage vessels under MACT CC because they are less than 40 cubic meters.

Tank D-20 is not subject to the requirements to MACT CC because it is not associated with a process unit. In accordance with 63.640(c)(2) only storage vessels associated with a process unit are subject to MACT CC. Tank D-20 receives skimmed hydrocarbons (weathered reformate) from remediation system wells.

Tanks T60, T4501, T4502, T4503, T4504, T4507, T4508, T4514, T4515, T4516, T4517 and T4518 are not considered storage vessels under MACT CC because they are wastewater storage tanks. These tanks are subject to the wastewater treatment requirements in MACT CC.

53.27 Upon a demonstration of compliance with the standards in §63.660 by the compliance dates specified in §63.640(h), the standards in this section shall no longer apply. (63.646)

The notice of compliance status submitted on September 19, 2016 did not indicate that any of the Group 1 storage tanks was in compliance with the requirements in 63.660, thus the requirements in 63.646 still apply. The September 19, 2016 notice indicates that the future compliance date is at the next emptying and degassing, or by February 1, 2026.

53.28 Overlap with storage vessel regulations:

53.28.1 After the compliance dates specified in 63.640(h), a Group 2 storage vessel that is subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in 63.640(n)(8). After the compliance dates specified in 63.640(h), a Group 2 storage vessel that is subject to the provisions of 40 CFR part 61, subpart Y, is required to comply only with the requirements of 40 CFR part 61, subpart Y, except as provided in 63.740(n)(10). (63.640(n)(1)) The requirements in 40 CFR Part 60 Subpart Kb are included in Condition 48. No specific equipment has been identified at this facility that falls under this overlap category.

53.28.2 After the compliance dates specified in 63.640(h), a Group 1 storage vessel that is also subject to 40 CFR part 60, subpart Kb, is required to comply only with either 40 CFR part 60, subpart Kb, except as provided in 63.640(n)(8) or this subpart. After the compliance dates specified in 63.640(h), a Group 1 storage vessel that is also subject to 40 CFR part 61, subpart Y, is required to comply only with either 40 CFR part 61, subpart Y, except as provided in 63.640(n)(10) or this subpart. (63.640(n)(2)) The requirements in 40 CFR Part 60 Subpart Kb are included in Condition 48.

The following tanks fall under the provisions in 63.640(n)(2): T34, T55, T96, T97, T116, T775 and T2010.

53.28.3 After the compliance dates specified in 63.640(h), a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subpart K or Ka, is required to only comply with the provisions of this subpart. (63.640(n)(5))

The following tank falls under the provisions in 63.640(n)(5): T1

53.28.4 Storage vessels described by 63.640(n)(1) are to comply with 40 CFR part 60, subpart Kb, except as provided in 63.640(n)(8)(i) through (vi). Storage vessels described by 63.640(n)(2) electing to comply with part 60, subpart Kb of this chapter shall comply with subpart Kb except as provided in 63.640(n)(8)(i) through (viii). (63.640(n)(8))

53.28.4.1 Storage vessels that are to comply with §60.112b(a)(2) of subpart Kb are exempt from the secondary seal requirements of §60.112b(a)(2)(i)(B) during the gap measurements for the primary seal required by §60.113b(b) of subpart Kb. (63.640(n)(8)(i))

53.28.4.2 If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113b(b) of this chapter or to inspect the vessel to determine compliance with §60.113b(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in 63.640(h) for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW. (63.640(n)(8)(ii))

53.28.4.3 If a failure is detected during the inspections required by §60.113b(a)(2) or during the seal gap measurements required by §60.113b(b)(1), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator. (63.640(n)(8)(iii))

53.28.4.4 If an extension is utilized in accordance with 63.640(n)(8)(iii), the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §60.113b(a)(2) or §60.113b(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied. (63.640(n)(8)(iv))

53.28.4.5 Owners and operators of storage vessels complying with subpart Kb of part 60 may submit the inspection reports required by §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb as part of the periodic reports required by this subpart, rather than within the 30-day period specified in §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb. (63.640(n)(8)(v))

53.28.4.6 The reports of rim seal inspections specified in §60.115b(b)(2) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §60.113b(b)(4). Documentation of the inspections shall be recorded as specified in §60.115b(b)(3). (63.640(n)(8)(vi))

53.28.4.7 To be in compliance with §60.112b(a)(1)(iv) or (a)(2)(ii) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.*, pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the "no visible gap" requirement. (63.640(n)(8)(vii))

53.28.4.8 If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of §63.670 instead of the requirements referenced from part 60, subpart Kb of this chapter for that flare. (63.640(n)(8)(viii))

<u>Group 1 Storage Vessels:</u>

The following tanks are Group 1 storage vessels that do not meet the overlap provisions in Condition 53.28.2: T1, T58, T67, T70, T75, T77, T78, T80, T776, T777, and T778.

53.29 Each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of §§63.119 through 63.121 (40 CFR Part 63 Subpart G, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater) except as provided in 63.646(b) through (l). (63.646(a))

The relevant requirements from 40 CFR Part 63 Subpart G, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater, are as follows.

The requirements below reflect the rule language in 40 CFR Part 63 Subpart G, as of the latest revisions to 40 CFR Part 63 Subpart G published in the Federal Register on November 19, 2020. However, the permittee is subject to the latest version of 40 CFR Part 63 Subpart G.

53.29.1 For each storage vessel to which this subpart applies, the owner or operator shall comply with the requirements of 63.119(a)(1), (a)(2), (a)(3), and (a)(4) according to the schedule provisions of §63.100 of subpart F of this part. (63.119(a))

53.29.1.1 For each Group 1 storage vessel (as defined in table 5 of this subpart for existing sources and table 6 of the subpart for new sources) storing a liquid for which the maximum true vapor pressure of the total organic hazardous air pollutants in the liquid is less than 76.6 kilopascals, the owner or operator shall reduce hazardous air pollutants emissions to the atmosphere either by operating and maintaining a fixed roof and internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, a closed vent system and control device, routing the emissions to a process or a fuel gas system, or vapor balancing in accordance with the requirements in 63.119(b), (c), (d), (e), (f), or (g), or equivalent as provided in §63.121 of this subpart. (63.119(a)(1)) Note that source is complying with these requirements by operating and maintaining a fixed roof tanks with an internal floating roof and external floating roof tanks.

53.29.2 The owner or operator who elects to use a fixed roof and an internal floating roof, as defined in §63.111 of this subpart, to comply with the requirements of 63.119(a)(1) shall comply with the requirements specified in 63.119(b)(1) through (b)(6). (63.119(b)) Note that as indicated in Condition 53.31, paragraphs (b)(5) and (6) do not apply.

53.29.3 The owner or operator who elects to use an external floating roof, as defined in §63.111 of this subpart, to comply with the requirements of 63.119(a)(1) shall comply with the requirements specified in 63.119(c)(1) through (c)(4). (63.119(c)) Note that as indicated in Condition 53.31, paragraph (c)(2) does not apply.

53.29.4 To demonstrate compliance with §63.119(b) of this subpart (storage vessel equipped with a fixed roof and internal floating roof) or with §63.119(d) of this subpart (storage vessel equipped with an external floating roof converted to an internal floating roof), the owner or operator shall comply with the requirements in 63.120(a)(1) through (a)(7). (63.120(a))

53.29.5 To demonstrate compliance with §63.119(c) of this subpart (storage vessel equipped with an external floating roof), the owner or operator shall comply with the requirements specified in 63.120(b)(1) through (b)(10). (63.120(b))

53.30 As used in this section, all terms not defined in §63.641 shall have the meaning given them in 40 CFR part 63, subparts A or G. The Group 1 storage vessel definition presented in §63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of §63.119 of subpart G of this part. (63.646(b)). The methods in 63.646(b)(1) and (2) apply with respect to determining the annual average HAP content for purposes of determining group type.

53.31 The following paragraphs do not apply to storage vessels at existing sources subject to this subpart: §63.119 (b)(5), (b)(6), (c)(2), and (d)(2). (63.646(c))

53.32 The following paragraphs apply to references 63.646(d), (h), (i), (j) and (k).

53.33 When complying with the inspection requirements of §63.120 of subpart G of this part, owners and operators of storage vessels at existing sources subject to this subpart are not required to comply with the provisions for gaskets, slotted membranes, and sleeve seals. (63.646(e))

53.34 The following 63.646(f)(1), (f)(2), and (f)(3) apply to Group 1 storage vessels at existing sources (63.646(f)):

53.34.1 If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access. (63.646(f)(1))

53.34.2 Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting. (63.646(f)(2))

53.34.3 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. (63.646(f)(3))

53.35 Failure to perform inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart. (63.646(g))

53.36 The State or local permitting authority can waive the notification requirements of §§63.120(a)(5), 63.120(a)(6), 63.120(b)(10)(ii), and 63.120(b)(10)(iii) for all or some storage vessels at petroleum refineries subject to this subpart. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in §63.120(a)(6) or §63.120(b)(10)(iii) for all storage vessels at a refinery or for individual storage vessels on a case-by-case basis. (63.646(l))

Group 2 Storage Vessels

The following tanks are Group 2 storage vessels that do not meet the overlap provisions in Condition 53.28.1: T2, T3, T52, T62, T94, T774, T2006, T3201, T3801, T57, T59, T64, T65, T66, T68, T69, T71, T72, T74, T76, T105, T112, T140, T142, T144, T145, T146, T147, T182, T191, T192, T193 and T194.

53.37 Each owner or operator subject to the storage vessel provisions in §63.646 shall keep the records specified in §63.123 of subpart G except as specified in 63.655(i)(1)(i) through (iv). Each owner or operator subject to the storage vessel provisions in §63.660 shall keep records as specified in 63.655(i)(1)(v) and (vi). (63.655(i)(1)) The requirements in 40 CFR Part 63 Subparts G and CC that apply to Group 2 storage vessels are as follows:

53.37.1 If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained. (63.655(i)(1)(iv))

53.37.2 Each owner or operator of a Group 1 or Group 2 storage vessel shall keep readily accessible records showing the dimensions of the storage vessel and an analysis showing the capacity of the storage vessel. This record shall be kept as long as the storage vessel retains Group 1 or Group 2 status and is in operation. For each Group 2 storage vessel, the owner or operator is not required to comply with any other provisions of §§63.119 through 63.123 of this subpart other than those required by this paragraph unless such vessel is part of an emissions average as described in §63.150 of this subpart. (63.123(a))

Wastewater Provisions (63.647)

The refinery is subject to these requirements.

53.38 Overlap with other regulations for wastewater: After the compliance dates specified in 63.640 (h) a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart. (63.640(o)(1))

T4514 and T4515 fall under this provision – they need only comply with the provisions of 40 CFR Part 63 Subpart CC.

53.39 Except as provided in 63.647(b) and (c), each owner or operator of a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of this chapter for each process wastewater stream that meets the definition in §63.641. (63.647(a))

53.40 As used in this section, all terms not defined in §63.641 shall have the meaning given them in the Clean Air Act or in 40 CFR part 61, subpart FF, §61.341. (63.647(b))

53.41 If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 61, subpart FF of this chapter, or the requirements of §63.670. (63.647(c))

53.42 Each owner or operator required under subpart FF of 40 CFR part 61 to perform periodic measurement of benzene concentration in wastewater, or to monitor process or control device operating parameters shall operate in a manner consistent with the minimum or maximum (as appropriate) permitted concentration or operating parameter values. Operation of the process, treatment unit, or control device resulting in a measured concentration or operating parameter value outside the permitted limits shall constitute a violation of the emission standards. Failure to perform required leak monitoring for closed vent systems and control devices or failure to repair leaks within the time period specified in subpart FF of 40 CFR part 61 shall constitute a violation of the standard. (63.647(d))

Equipment Leak Standards (63.648)

These requirements are applicable to equipment leaks from petroleum refining process units and gasoline terminals classified under SIC 2911 that emit or have equipment containing or contacting one or more of the HAPs listed in Table 1 of 40 CFR Part 63 Subpart CC. Note that definition of process unit in §63.641 includes associated storage vessels.

53.43 <u>Overlap with other regulations for equipment leaks:</u>

53.43.1 After the compliance dates specified in 63.640(h), equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart. (63.640(p)(1))

Some of the waste streams associated with the GBR unit (F114) are subject to the requirements in 40 CFR Part 61 Subpart J and under the provisions in 63.740(p)(1) only have to comply with the requirements in 40 CFR Part 63 Subpart CC.

53.43.2 Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa, except that pressure relief devices in organic HAP service must only comply with the requirements in §63.648(j). (63.640(p)(2))

The following sources fall under the provisions of 63.640(p)(2): F102, F103, F104, F105, F106, F108, F109, F110, F111, F112, F113, F114, F115, F116, F200, F202, F205, F206, F207, F208, F209, F210 and F107 (unpermitted) components that meet the applicability criteria in §60.590a.

Equipment leaks that do not meet the overlap provisions in Condition 53.43.2 and that are subject to the requirements in 40 CFR Part 63 Subpart CC are as follows: the rail loading rack (R101) (except for the components associated with the P1 rail rack RSR compliance project (F205)) and unpermitted components (F107) associated with petroleum refinery process units that <u>do not</u> meet the applicability criteria in §60.590a are subject to these requirements. Note that process units include associated storage vessels.

Note that many unpermitted components do not have identification numbers or names and are not specifically listed in the table in Section I, Condition 5.1, thus the above list is not necessarily inclusive.

53.44 Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60, subpart VV, and 63.648(b) except as provided in 63.648(a)(1) through (3) and (c) through (j). Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in 63.648(c) through (j). (63.648(a)) The requirements in 40 CFR Part 60 Subpart VVV are included in Condition 64 of this permit.

53.44.1 For purposes of compliance with this section, the provisions of 40 CFR part 60, subpart VV apply only to equipment in organic HAP service, as defined in §63.641 of this subpart. (63.648(a)(1))

53.44.2 Calculation of percentage leaking equipment components for subpart VV of 40 CFR part 60 may be done on a process unit basis or a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made. (63.648(a)(2))

53.44.3 If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 60, subpart VV of this chapter, or the requirements of §63.670. (63.648(a)(3))

53.45 Reciprocating pumps in light liquid service are exempt from §§63.163 and 60.482 if recasting the distance piece or reciprocating pump replacement is required. (63.648(f))

53.46 Compressors in hydrogen service are exempt from the requirements of paragraphs (a) and (c) of this section if an owner or operator demonstrates that a compressor is in hydrogen service. (63.648(g))

53.46.1 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. (63.648(g)(1))

53.46.2 For a piece of equipment to be considered in hydrogen service, it must be determined that the percentage hydrogen content can be reasonably expected always to exceed 50 percent by volume. (63.648(g)(2)) Note that the determination shall be made in accordance with the requirements in 63.648(g)(2)(i).

53.47 Each owner or operator of a source subject to the provisions of this subpart must maintain all records for a minimum of 5 years. (63.648(h))

53.48 Reciprocating compressors are exempt from seal requirements if recasting the distance piece or compressor replacement is required. (63.648(i))

53.49 Except as specified in 63.648(j)(4), the owner or operator must comply with the requirements specified in 63.648(j)(1) and (2) for pressure relief devices, such as relief valves or rupture disks, in organic HAP gas or vapor service instead of the pressure relief device requirements of §60.482-4 of this chapter, §60.482-4a of this chapter, or §63.165, as applicable. Except as specified in 63.648(j)(4) and (5), the owner or operator must also comply with the requirements specified in 63.648(j)(3) for all pressure relief devices in organic HAP service. (63.648(j))

53.49.1 *Operating requirements.* Except during a pressure release, operate each pressure relief device in organic HAP gas or vapor service with an instrument reading of less than 500 ppm above background as detected by Method 21 of 40 CFR part 60, appendix A-7. (63.648(j)(1))

53.49.2 *Pressure release requirements.* For pressure relief devices in organic HAP gas or vapor service, the owner or operator must comply with the applicable requirements in 63.648(j)(2)(i) through (iii) following a pressure release. (63.648(j)(2))

53.49.2.1 If the pressure relief device does not consist of or include a rupture disk, conduct instrument monitoring, as specified in §60.485(c) of this chapter, §60.485a(c) of this chapter, or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm. (63.648(j)(2)(i))

53.49.2.2 If the pressure relief device includes a rupture disk, either comply with the requirements in 63.648(j)(2)(i) (not replacing the rupture disk) or install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator must conduct instrument monitoring, as specified in §60.485(c) of this chapter, §60.485a(c) of this chapter or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm. (63.642(j)(2)(ii))

53.49.2.3 If the pressure relief device consists only of a rupture disk, install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator may not initiate startup of the equipment served by the rupture disk until the rupture disc is replaced. The owner or operator must conduct instrument monitoring, as specified in §60.485(c) of this chapter, §60.485a(c) of this chapter, or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm. (63.648(j)(2)(iii))

53.49.3 *Pressure release management.* Except as specified in 63.648(j)(4) and (5), the owner or operator shall comply with the requirements specified in 63.648(j)(3)(i) through (v) for all pressure relief devices in organic HAP service no later than January 30, 2019. (63.648(j)(3))

53.49.3.1 The owner or operator must equip each affected pressure relief device with a device(s) or use a monitoring system that is capable of (63.648(j)(3)(i)):

a. Identifying the pressure release (63.648(j)(3)(i)(A));

b. Recording the time and duration of each pressure release (63.648(j)(3)(i)(B)); and

c. Notifying operators immediately that a pressure release is occurring. The device or monitoring system may be either specific to the pressure relief device itself or may be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor. (63.648(j)(3)(i)(C))

53.49.3.2 The owner or operator must apply at least three redundant prevention measures to each affected pressure relief device and document these measures. Examples of prevention measures include the equipment identified in 63.648(j)(3)(ii)(A) through (E). (63.648(j)(3)(ii))

53.49.3.3 If any affected pressure relief device releases to atmosphere as a result of a pressure release event, the owner or operator must perform root cause analysis and corrective action analysis according to the requirement in 63.648(j)(6) and implement corrective actions according to the requirements in 63.648(j)(7). The owner or operator must also calculate the quantity of organic HAP released during each pressure release event and report this quantity as required in §63.655(g)(10)(iii). Calculations may be based on data from the pressure relief device monitoring alone or in combination with process parameter monitoring data and process knowledge. (63.648(j)(3)(iii))

53.49.3.4 The owner or operator shall determine the total number of release events occurred during the calendar year for each affected pressure relief device separately. The owner or operator shall also determine the total number of release events for each pressure relief device for which the root cause analysis concluded that the root cause was a *force majeure* event, as defined in this subpart. (63.648(j)(3)(iv))

53.49.3.5 Except for pressure relief devices described in 63.648(j)(4) and (5), the following release events from an affected pressure relief device are a violation of the pressure release management work practice standards: (63.648(j)(3)(v))

a. Any release event for which the root cause of the event was determined to be operator error or poor maintenance. (63.648(j)(3)(v)(A))

b. A second release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment. (63.648(j)(3)(v)(B))

c. A third release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for any reason. (63.648(j)(3)(v)(C))

53.49.4 *Pressure relief devices routed to a control device.* (63.648(j)(4))

53.49.4.1 If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is not required to comply with 63.648(j)(1), (2), or (3) (if applicable). (63.648(j)(4)(i))

53.49.4.2 If a pilot-operated pressure relief device is used and the primary release valve is routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is required to comply only with 63.648(j)(1) and (2) for the pilot discharge vent and is not required to comply with 63.648(j)(3) for the pilot-operated pressure relief device. (63.648(j)(4)(ii))

53.49.4.3 If a balanced bellows pressure relief device is used and the primary release valve is routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is required to comply only with 63.68(j)(1) and (2) for the bonnet vent and is not required to comply with p63.648(j)(3) for the balanced bellows pressure relief device. (63.648(j)(4)(iii))

53.49.4.4 Both the closed vent system and control device (if applicable) referenced in 63.648(j)(4)(i) through (iii) must meet the requirements of §63.644. When complying with 63.648 (j)(4), all references to “Group 1 miscellaneous process vent” in §63.644 mean “pressure relief device.” (63.648(j)(4)(iv))

53.49.4.5 If a pressure relief device complying with 63.648(j)(4) is routed to the fuel gas system, then on and after January 30, 2019, any flares receiving gas from that fuel gas system must be in compliance with §63.670. (63.648(j)(4)(v))

53.49.5 *Pressure relief devices exempted from pressure release management requirements.* The following types of pressure relief devices are not subject to the pressure release management requirements in 63.648(j)(3). (63.648(j)(5))

53.49.5.1 Pressure relief devices in heavy liquid service, as defined in §63.641. (63.648(j)(5)(i))

53.49.5.2 Pressure relief devices that only release material that is liquid at standard conditions (1 atmosphere and 68 degrees Fahrenheit) and that are hard-piped to a controlled drain system (*i.e.*, a drain system meeting the requirements for Group 1 wastewater streams in §63.647(a)) or piped back to the process or pipeline. (63.648(j)(5)(ii))

53.49.5.3 Thermal expansion relief valves. (63.648(j)(5)(iii))

53.49.5.4 Pressure relief devices designed with a set relief pressure of less than 2.5 psig. (63.648(j)(5)(iv))

53.49.5.5 Pressure relief devices that do not have the potential to emit 72 lbs/day or more of VOC based on the valve diameter, the set release pressure, and the equipment contents. (63.648(j)(5)(v))

53.49.5.6 Pressure relief devices on mobile equipment. (63.648(j)(5)(vi))

53.49.6 *Root cause analysis and corrective action analysis.* A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a release event. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 63.648(j)(6)(i) through (iv). (63.648(j)(6))

53.49.6.1 You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices installed on the same equipment to release. (63.648(j)(6)(i))

53.49.6.2 You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices to release, regardless of the equipment served, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart. (63.648(j)(6)(ii))

53.49.6.3 Except as provided in 63.648(j)(6)(i) and (ii), if more than one pressure relief device has a release during the same time period, an initial root cause analysis shall be conducted separately for each pressure relief device that had a release. If the initial root cause analysis indicates that the release events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted. (63.648(j)(6)(iii))

53.49.7 *Corrective action implementation.* Each owner or operator required to conduct a root cause analysis and corrective action analysis as specified in 63.648(j)(3)(iii) and (j)(6) shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in 63.648(j)(7)(i) through (iii). (63.648(j)(7))

53.49.7.1 All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event. (63.648(j)(7)(i))

53.49.7.2 For corrective actions that cannot be fully implemented within 45 days following the event 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. (63.648(j)(7)(ii))

53.49.7.3 No later than 45 days following the event 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. (63.648(j)(7)(iii))

Gasoline Loading Rack Provisions (63.650)

The following sources are subject to this requirement: R101

53.50 <u>Overlap of subpart CC with other regulations for gasoline loading racks</u>. After the compliance dates specified in 63.640(h), a Group 1 gasoline loading rack that is part of a source subject to subpart CC and also is subject to the provisions of 40 CFR part 60, subpart XX is required to comply only with this subpart. (63.640(r)) No specific equipment has been identified at this facility that falls under this overlap category.

53.51 Except as provided in 63.640(b) through (d), each owner or operator of a Group 1 gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with subpart R of this part, §§63.421, 63.422(a) through (c) and (e), 63.425(a) through (c) and (e) through (i), 63.427(a) and (b), and 63.428(b), (c), (g)(1), (h)(1) through (3), and (k). (63.650(a)). The requirements in 40 CFR Part 63 Subpart R are included in Condition 52 of this permit.

53.52 As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart R. The §63.641 definition of "affected source" applies under this section. (63.650(b))

53.53 If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart R of this part, or the requirements of §63.670. (63.650(d))

Heat exchange systems (63.654)

Heat exchange systems associated with the Y1, Y2, Y3 and Y4 cooling towers are subject to these requirements.

53.54 Except as specified in 63.654(b), the owner or operator of a heat exchange system that meets the criteria in §63.640(c)(8) must comply with the requirements of 63.654(c) through (g). (63.654(a))

53.55 A heat exchange system is exempt from the requirements in 63.654(c) through (g) if all heat exchangers within the heat exchange system either: (63.654(b))

53.55.1 Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side (63.654(b)(1)); or

53.55.2 Employ an intervening cooling fluid containing less than 5 percent by weight of total organic HAP, as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes. (63.654(b)(2))

53.56 The owner or operator must perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each heat exchange system subject to the requirements of this subpart according to the procedures in 63.654(c)(1) through (6). (63.654(c)) Note that the requirements for once-through heat exchange systems in (c)(2) and new sources in (c)(5) were not included as they do not apply.

53.56.1 *Monitoring* locations *for closed-loop recirculation heat exchange systems.* For each closed loop recirculating heat exchange system, collect and analyze a sample from the location(s) described in either 63.654(c)(1)(i) or (c)(1)(ii). (63.654(c)(1))

53.56.2 *Monitoring method.* Determine the total strippable hydrocarbon concentration (in parts per million by volume (ppmv) as methane) at each monitoring location using the "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources" Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) using a flame ionization detector (FID) analyzer for on-site determination as described in Section 6.1 of the Modified El Paso Method. (63.654(c)(3))

53.56.3 *Monitoring frequency and leak action level for existing sources.* For a heat exchange system at an existing source, the owner or operator must comply with the monitoring frequency and leak action level as defined in 63.654(c)(4)(i) or comply with the monitoring frequency and leak action level as defined in 63.654(c)(4)(ii). The owner or operator of an affected heat exchange system may choose to comply with 63.654(c)(4)(i) for some heat exchange systems at the petroleum refinery and comply with 63.654(c)(4)(ii) for other heat exchange systems. However, for each affected heat exchange system, the owner or operator of an affected heat exchange system must elect one monitoring alternative that will apply at all times. If the owner or operator intends to change the monitoring alternative that applies to a heat exchange system, the owner or operator must notify the Administrator 30 days in advance of such a change. All "leaks" identified prior to changing monitoring alternatives must be repaired. The monitoring frequencies specified in 63.654(c)(4)(i) and (ii) also apply to the inlet water feed line for a once-through heat exchange system, if monitoring of the inlet water feed is elected as provided in 63.654(c)(2)(ii). (63.654(c)(4))

53.56.3.1 Monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 6.2 ppmv. (63.654(c)(4)(i))

53.56.3.2 Monitor quarterly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv unless repair is delayed as provided in 63.654(f). If a repair is delayed as provided in 63.654(f), monitor monthly. (63.654(c)(4)(ii))

53.56.4 *Leak definition.* A leak is defined as described in paragraph (c)(6)(i) or (c)(6)(ii) of this section, as applicable. (63.654(c)(6)) Note that since the heat exchange systems are closed loop systems only paragraph (c)(6)(ii) was included.

53.56.4.1 For all other heat exchange systems, a leak is detected if a measurement value of the sample taken from a location specified in either 63.654(c)(1)(i), (c)(1)(ii), or (c)(2)(i) equals or exceeds the leak action level.

53.57 If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in 63.654(e) and (f). Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in 63.654(c)(3) of this section to verify that the measured concentration is below the applicable action level. Actions that can be taken to achieve repair include but are not limited to the provisions in 63.654(d)(1) through (5). (63.654(d))

53.58 If the owner or operator detects a leak when monitoring a cooling tower return line under 63.654(c)(1)(i), the owner or operator may conduct additional monitoring of each heat exchanger or group of heat exchangers associated with the heat exchange system for which the leak was detected as provided under 63.654(c)(1)(ii). If no leaks are detected when monitoring according to the requirements of 63.654(c)(1)(ii), the heat exchange system is considered to meet the repair requirements through re-monitoring of the heat exchange system as provided in 63.654(d). (63.654(e))

53.59 The owner or operator may delay the repair of a leaking heat exchanger when one of the conditions in 63.654(f)(1) or (f)(2) is met and the leak is less than the delay of repair action level specified in 63.654(f)(3). The owner or operator must determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak. (63.654(f))

53.59.1 If the repair is technically infeasible without a shutdown and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during the delay of repair, the owner or operator may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level. (63.654(f)(1))

53.59.2 If the necessary equipment, parts, or personnel are not available and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during the delay of repair, the owner or operator may delay the repair for a maximum of 120 calendar days. The owner or operator must demonstrate that the necessary equipment, parts, or personnel were not available. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level. (63.654(f)(2))

53.59.3 The delay of repair action level is a total strippable hydrocarbon concentration (as methane) in the stripping gas of 62 ppmv. The delay of repair action level is assessed as described in 63.654(f)(3)(i) or (f)(3)(ii), as applicable. (63.654(f)(3)) Note that since the heat exchange systems are closed loop systems only paragraph (f)(3)(ii) was included.

53.59.3.1 For all other heat exchange systems, the delay of repair action level is exceeded if a measurement value of the sample taken from a location specified in either 63.654(c)(1)(i), (c)(1)(ii), or (c)(2)(i) equals or exceeds the delay of repair action level. (63.654(f)(3)(ii))

53.60 To delay the repair under 63.654(f), the owner or operator must record the information in 63.654(g)(1) through (4). (63.654(g))

Reporting and Recordkeeping Requirements (63.655)

53.61 Each owner or operator subject to the wastewater provisions in §63.647 shall comply with the recordkeeping and reporting provisions in §§61.356 and 61.357 of 40 CFR part 61, subpart FF unless they are complying with the wastewater provisions specified in paragraph (o)(2)(ii) of §63.640. There are no additional reporting and recordkeeping requirements for wastewater under this subpart unless a wastewater stream is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in 63.655(f)(5) and (g)(8). (63.655(a))

53.62 Each owner or operator subject to the gasoline loading rack provisions in §63.650 shall comply with the recordkeeping and reporting provisions in §63.428 (b) and (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. These requirements are summarized in table 4 of this subpart. There are no additional reporting and recordkeeping requirements for gasoline loading racks under this subpart unless a loading rack is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in 63.655(f)(5) and (g)(8). (63.655(b))

53.63 Each owner or operator subject to the equipment leaks standards in §63.648 shall comply with the recordkeeping and reporting provisions in 63.655(d)(1) through (d)(6). (63.655(d))

53.64 Each owner or operator of a source subject to this subpart shall submit the reports listed in 63.655(e)(1) through (e)(3) except as provided in 63.655(h)(5), and shall keep records as described in 63.655(i). (63.655(e))

53.64.1 A Notification of Compliance Status report as described in 63.655(f); (63.655(e)(1))

53.64.2 Periodic Reports as described in 63.655(g) (63.655(e)(2)); and

53.64.3 Other reports as described in 63.655(h). (63.655(e)(3))

53.65 Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in §63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with §63.640(l)(3) and for storage vessels subject to the compliance schedule specified in §63.640(h)(2). Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(2) shall be submitted according to 63.655(f)(6). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If the required information has been submitted before the date 150 days after the compliance date specified in §63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in §63.640(h). If an owner or operator submits the information specified in 63.655(f)(1) through (5) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. Each owner or operator of a gasoline loading rack classified under Standard Industrial Classification Code 2911 located within a contiguous area and under common control with a petroleum refinery subject to the standards of this subpart shall submit the Notification of Compliance Status report required by subpart R of this part within 150 days after the compliance dates specified in §63.640(h). (63.655(f)) Note that 63.655(f)(5) was not included because it applies to an emissions average which does not apply.

53.65.1 The Notification of Compliance Status report shall include the information specified in 63.655(f)(1)(i) through (viii). (63.655(f)(1))

53.65.2 If initial performance tests are required by §§63.643 through 63.653, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source. On and after February 1, 2016, for data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results in accordance with §63.655(h)(9) by the date that you submit the Notification of Compliance Status, and you must include the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted in the Notification of Compliance Status. All other performance test results must be reported in the Notification of Compliance Status. (63.655(f)(2))

53.65.2.1 For additional tests performed using the same method, the results specified in 63.655(f)(1) shall be submitted, but a complete test report is not required. (63.655(f)(2)(i))

53.65.2.2 A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method. (63.655(f)(2)(ii))

53.65.2.3 Performance tests are required only if specified by §§ 63.643 through 63.653 of this subpart. Initial performance tests are required for some kinds of emission points and controls. Periodic testing of the same emission point is not required. (63.655(f)(2)(iii))

53.65.3 For each monitored parameter for which a range is required to be established under §63.120(d) of subpart G or §63.985(b) of subpart SS for storage vessels or §63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in 63.655(f)(3)(i) through (iii). (63.655(f)(3))

53.65.4 Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status report, unless the results are required to be submitted electronically by §63.655(h)(9). For performance evaluation results required to be submitted through CEDRI, submit the results in accordance with §63.655(h)(9) by the date that you submit the Notification of Compliance Status and include the process unit where the CMS is installed, the parameter measured by the CMS, and the date that the performance evaluation was conducted in the Notification of Compliance Status. (63.655(f)(4))

53.65.5 Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(2) shall be submitted no later than 60 days after the end of the 6-month period during which the change or addition was made that resulted in the Group 1 emission point or the existing Group 1 storage vessel was brought into compliance, and may be combined with the periodic report. Six-month periods shall be the same 6-month periods specified in 63.655(g). The Notification of Compliance Status report shall include the information specified in 63.655(f)(1) through (f)(5). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, as part of the periodic report, or in any combination of these four. If the required information has been submitted before the date 60 days after the end of the 6-month period in which the addition of the Group 1 emission point took place, a separate Notification of Compliance Status report is not required within 60 days after the end of the 6-month period. If an owner or operator submits the information specified in 63.655(f)(1) through (f)(5) at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information. (63.655(f)(6))

53.66 The owner or operator of a source subject to this subpart shall submit Periodic Reports no later than 60 days after the end of each 6-month period when any of the information specified in 63.655(g)(1) through (7) or 63.655(g)(9) through (14) is collected. The first 6-month period shall begin on the date the Notification of Compliance Status report is required to be submitted. A Periodic Report is not required if none of the events identified in 63.655(g)(1) through (7) or 63.655(g)(9) through (14) occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission averages, as provided in 63.655(g)(8). An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this 63.655(g) if the reports contain the information required by 63.655(g)(1) through (14). (63.655(g))

53.66.1 For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in 63.655(g)(2) through (5). Information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source complying with §63.646. (63.655(g)(1))

53.66.2 For internal floating roof tanks, the information in 63.655(g)(2)(i) or (ii), as applicable.

53.66.3 For external floating roof tanks, the information in 63.655(g)(3)(i) or (ii), as applicable.

53.66.4 An owner or operator who elects to comply with §63.646 or §63.660 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in 63.655(g)(5)(i) through (v), as applicable. (63.655(g)(5))

53.66.5 For miscellaneous process vents for which continuous parameter monitors are required by this subpart, periods of excess emissions shall be identified in the Periodic Reports and shall be used to determine compliance with the emission standards. (63.655(g)(6))

53.66.6 If a performance test for determination of compliance for a new emission point subject to this subpart or for an emission point that has changed from Group 2 to Group 1 is conducted during the period covered by a Periodic Report, the results of the performance test shall be included in the Periodic Report. (63.655(g)(7))

53.66.7 For heat exchange systems, Periodic Reports must include the information in 63.655(g)(9)(i) through (v). (63.655(g)(9))

53.66.8 For pressure relief devices subject to the requirements §63.648(j), Periodic Reports must include the information specified in 63.655(g)(10)(i) through (iv). (63.655(g)(10))

53.66.9 For flares subject to §63.670, Periodic Reports must include the information specified in 63.655(g)(11)(i) through (iv). (63.655(g)(11))

53.66.10 For maintenance vents subject to the requirements in §63.643(c), Periodic Reports must include the information specified in 63.655(g)(13)(i) through (iv) for any release exceeding the applicable limits in §63.643(c)(1). For the purposes of this reporting requirement, owners or operators complying with §63.643(c)(1)(iv) must report each venting event for which the lower explosive limit is 20 percent or greater; owners or operators complying with §63.643(c)(1)(v) must report each venting event conducted under those provisions and include an explanation for each event as to why utilization of this alternative was required. (63.655(g)(13))

53.66.11 Any changes in the information provided in a previous Notification of Compliance Status report. (63.655(g)(14))

53.67 Other reports shall be submitted as specified in subpart A of this part and as follows (63.655(h)):

53.67.1 For storage vessels, notifications of inspections as specified in 63.655(h)(2)(i) and (ii). (63.655(h)(2))

53.67.2 An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in 63.655(i). Such requests shall meet the requirements in 63.655(h)(5)(i) through (iv). (63.640(h)(5))

53.67.3 The owner or operator shall submit the information specified in 63.655(h)(6)(i) through (h)(6)(iii), as applicable. For existing sources, this information shall be submitted in the initial Notification of Compliance Status report. For a new source, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A of this part. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal. (63.655(h)(6))

53.67.4 The owner or operator of a heat exchange system at an existing source must notify the Administrator at least 30 calendar days prior to changing from one of the monitoring options specified in §63.654(c)(4) to the other. (63.655(h)(7))

53.67.5 For fenceline monitoring systems subject to §63.658, each owner or operator shall submit the following information (63.655(h)(8)(i) through (viii)) to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) on a quarterly basis. (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The first quarterly report must be submitted once the owner or operator has obtained 12 months of data. The first quarterly report must cover the period beginning on the compliance date that is specified in Table 11 of this subpart (Condition 53.3) and ending on March 31, June 30, September 30 or December 31, whichever date is the first date that occurs after the owner or operator has obtained 12 months of data (*i.e.*, the first quarterly report will contain between 12 and 15 months of data). Each subsequent quarterly report must cover one of the following reporting periods: Quarter 1 from January 1 through March 31; Quarter 2 from April 1 through June 30; Quarter 3 from July 1 through September 30; and Quarter 4 from October 1 through December 31. Each quarterly report must be electronically submitted no later than 45 calendar days following the end of the reporting period. (63.655(h)(8))

53.67.6 On and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, the owner or operator shall submit the results according to the procedures in 63.655(h)(9)(i) and (ii). (63.655(h)(9))

53.67.7 *Extensions to electronic reporting deadlines.* (63.655(h)(10))

53.67.7.1 If you are required to electronically submit a report through the Compliance and Emissions Data Reporting Interface (CEDRI) in the EPA's Central Data Exchange (CDX), and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description identifying the date(s) and time(s) the CDX or CEDRI were unavailable when you attempted to access it in the 5 business days prior to the submission deadline; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (63.655(10)(i))

53.67.7.2 If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. For the purposes of this paragraph, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage). If you intend to assert a claim of force majeure, you must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (63.655(h)(10)(ii))

53.68 *Recordkeeping.* Each owner or operator of a source subject to this subpart shall keep copies of all applicable reports and records required by this subpart for at least 5 years except as otherwise specified in 63.655(i)(1) through (12). All applicable records shall be maintained in such a manner that they can be readily accessed within 24 hours. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, flash drive, floppy disk, magnetic tape, or microfiche. (63.655(i))

53.68.1 Each owner or operator subject to the storage vessel provisions in §63.646 shall keep the records specified in §63.123 of subpart G except as specified in 63.655(i)(1)(i) through (iv). Each owner or operator subject to the storage vessel provisions in §63.660 shall keep records as specified in 63.655(i)(1)(v) and (vi). (63.655(i)(1))

53.68.2 Each owner or operator required to report the results of performance tests under 63.655(f) and (g)(7) shall retain a record of all reported results as well as a complete test report, as described in 63.655(f)(2)(ii) for each emission point tested. (63.655(i)(2))

53.68.3 Each owner or operator required to continuously monitor operating parameters under §63.644 for miscellaneous process vents or under §§63.652 and 63.653 for emission points in an emissions average shall keep the records specified in 63.655(i)(3)(i) through (i)(3)(v) unless an alternative recordkeeping system has been requested and approved under 63.655(h). (63.655(i)(3))

53.68.4 For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), the owner or operator shall keep a record of the information specified in either 63.655(i)(4)(i) or (ii), as applicable. (63.655(i)(4))

53.68.5 The owner or operator of a heat exchange system subject to this subpart shall comply with the recordkeeping requirements in 63.655(i)(5)(i) through (v) and retain these records for 5 years. (63.655(i)(5))

53.68.6 All other information required to be reported under 63.655(a) through (h) shall be retained for 5 years. (63.655(i)(6))

53.68.7 For fenceline monitoring systems subject to §63.658, each owner or operator shall keep the records specified in 63.655(i)(8)(i) through (x) on an ongoing basis. (63.655(i)(8))

53.68.8 For each flare subject to §63.670, each owner or operator shall keep the records specified in 63.655(i)(9)(i) through (xii) up-to-date and readily accessible, as applicable. (63.655(i)(9))

53.68.9 For each pressure relief device subject to the pressure release management work practice standards in §63.648(j)(3), the owner or operator shall keep the records specified in 63.655(i)(11)(i) through (iii). For each pilot-operated pressure relief device subject to the requirements at §63.648(j)(4)(ii), the owner or operator shall keep the records specified in 63.655(i)(11)(iv). (63.655(i)(11))

53.68.10 For each maintenance vent opening subject to the requirements in §63.643(c), the owner or operator shall keep the applicable records specified in 63.655(i)(12)(i) through (vi). (63.655(i)(12))

Fenceline monitoring provisions (63.658)

53.69 The owner or operator shall conduct sampling along the facility property boundary and analyze the samples in accordance with Methods 325A and 325B of appendix A of this part and 63.658(b) through (k). (63.658(a))

53.70 The target analyte is benzene. (63.658(b))

53.71 The owner or operator shall determine passive monitor locations in accordance with Section 8.2 of Method 325A of appendix A of this part. (63.658(c))

53.71.1 As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A of this part for siting passive monitors, means a wastewater treatment unit, process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations. For marine vessel loading operations, one passive monitor should be sited on the shoreline adjacent to the dock. For this subpart, an additional monitor is not required if the only emission sources within 50 meters of the monitoring boundary are equipment leak sources satisfying all of the conditions in 63.655(c)(1)(i) through (iv). (63.658(c)(1)) (63.658(c)(1))

53.71.1.1 The equipment leak sources in organic HAP service within 50 meters of the monitoring boundary are limited to valves, pumps, connectors, sampling connections, and open-ended lines. If compressors, pressure relief devices, or agitators in organic HAP service are present within 50 meters of the monitoring boundary, the additional passive monitoring location specified in Section 8.2.1.3 in Method 325A of appendix A of this part must be used. (63.658(c)(1)(i))

53.71.1.2 All equipment leak sources in gas or light liquid service (and in organic HAP service), including valves, pumps, connectors, sampling connections and open-ended lines, must be monitored using EPA Method 21 of 40 CFR part 60, appendix A-7 no less frequently than quarterly with no provisions for skip period monitoring, or according to the provisions of §63.11(c) Alternative Work practice for monitoring equipment for leaks. For the purpose of this provision, a leak is detected if the instrument reading equals or exceeds the applicable limits in 63.658(c)(1)(ii)(A) through (E).

53.71.1.3 All equipment leak sources in organic HAP service, including sources in gas, light liquid and heavy liquid service, must be inspected using visual, audible, olfactory, or any other detection method at least monthly. A leak is detected if the inspection identifies a potential leak to the atmosphere or if there are indications of liquids dripping. (63.658(c)(1)(iii))

53.71.1.4 All leaks identified by the monitoring or inspections specified in 63.658(c)(1)(ii) or (iii) must be repaired no later than 15 calendar days after it is detected with no provisions for delay of repair. If a repair is not completed within 15 calendar days, the additional passive monitor specified in Section 8.2.1.3 in Method 325A of appendix A of this part must be used. (63.658(c)(1)(iv))

53.71.2 The owner or operator may collect one or more background samples if the owner or operator believes that an offsite upwind source or an onsite source excluded under §63.640(g) may influence the sampler measurements. If the owner or operator elects to collect one or more background samples, the owner or operator must develop and submit a site-specific monitoring plan for approval according to the requirements in 63.658(i). Upon approval of the site-specific monitoring plan, the background sampler(s) should be operated co-currently with the routine samplers. (63.658(c)(2))

53.71.3 If there are 19 or fewer monitoring locations, the owner or operator shall collect at least one co-located duplicate sample per sampling period and at least one field blank per sampling period. If there are 20 or more monitoring locations, the owner or operator shall collect at least two co-located duplicate samples per sampling period and at least one field blank per sampling period. The co-located duplicates may be collected at any of the perimeter sampling. (63.658(c)(3))

53.71.4 The owner or operator shall follow the procedure in Section 9.6 of Method 325B of appendix A of this part to determine the detection limit of benzene for each sampler used to collect samples, background samples (if the owner or operator elects to do so), co-located samples and blanks. (63.658(c)(4))

53.72 The owner or operator shall collect and record meteorological data according to the applicable requirements in 63.658(d)(1) through (3). (63.658(d))

53.72.1 If a near-field source correction is used as provided in 63.658(i)(2) or if an alternative test method is used that provides time-resolved measurements, the owner or operator shall (63.658(d)(1)):

53.72.1.1 Use an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part. (63.658(d)(1)(i))

53.72.1.2 Collect and record hourly average meteorological data, including temperature, barometric pressure, wind speed and wind direction and calculate daily unit vector wind direction and daily sigma theta. (63.658(d)(1)(ii))

53.72.2 For cases other than those specified in 63.658(d)(1), the owner or operator shall collect and record sampling period average temperature and barometric pressure using either an on-site meteorological station in accordance with Section 8.3.1 through 8.3.3 of Method 325A of appendix A of this part or, alternatively, using data from a United States Weather Service (USWS) meteorological station provided the USWS meteorological station is within 40 kilometers (25 miles) of the refinery. (63.658(d)(2))

53.72.3 If an on-site meteorological station is used, the owner or operator shall follow the calibration and standardization procedures for meteorological measurements in EPA-454/B-08-002 (incorporated by reference—see §63.14). (63.658(d)(3))

53.73 The owner or operator shall use a sampling period and sampling frequency as specified in 63.658(e)(1) through (3). (63.658(e))

53.73.1 *Sampling period.* A 14-day sampling period shall be used, unless a shorter sampling period is determined to be necessary under 63.658(g) or (i). A sampling period is defined as the period during which sampling tube is deployed at a specific sampling location with the diffusive sampling end cap in-place and does not include the time required to analyze the sample. For the purpose of this subpart, a 14-day sampling period may be no shorter than 13 calendar days and no longer than 15 calendar days, but the routine sampling period shall be 14 calendar days. (63.658(e)(1))

53.73.2 *Base* sampling *frequency*. Except as provided in 63.658(e)(3), the frequency of sample collection shall be once each contiguous 14-day sampling period, such that the beginning of the next 14-day sampling period begins immediately upon the completion of the previous 14-day sampling period. (63.658(e)(2))

53.73.3 *Alternative sampling frequency for burden reduction.* When an individual monitor consistently achieves results at or below 0.9 μg/m^3, the owner or operator may elect to use the applicable minimum sampling frequency specified in 63.658(e)(3)(i) through (v) for that monitoring site. When calculating Δc for the monitoring period when using this alternative for burden reduction, zero shall be substituted for the sample result for the monitoring site for any period where a sample is not taken. (63.658(e)(3))

53.74 Within 45 days of completion of each sampling period, the owner or operator shall determine whether the results are above or below the action level as follows (63.658(f)):

53.74.1 The owner or operator shall determine the facility impact on the benzene concentration (Δc) for each 14-day sampling period according to either paragraph (f)(1)(i) or (ii) of this section, as applicable. (63.658(f)(1))

53.74.2 The owner or operator shall calculate the annual average Δc based on the average of the 26 most recent 14-day sampling periods. The owner or operator shall update this annual average value after receiving the results of each subsequent 14-day sampling period. (3.658(f)(2))

53.74.3 The action level for benzene is 9 micrograms per cubic meter (μg/m^3) on an annual average basis. If the annual average Δc value for benzene is less than or equal to 9 μg/m^3, the concentration is below the action level. If the annual average Δc value for benzene is greater than 9 μg/m^3, the concentration is above the action level, and the owner or operator shall conduct a root cause analysis and corrective action in accordance with 63.658(g) (Condition 53.75). (63.658(f)(3))

53.75 Within 5 days of determining that the action level has been exceeded for any annual average Δc and no longer than 50 days after completion of the sampling period, the owner or operator shall initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action, such as those described in 63.658(g)(1) through (4). The root cause analysis and initial corrective action analysis shall be completed and initial corrective actions taken no later than 45 days after determining there is an exceedance. Root cause analysis and corrective action may include, but is not limited to (63.658(g)):

53.75.1 Leak inspection using Method 21 of part 60, appendix A-7 of this chapter and repairing any leaks found. (63.658(g)(1))

53.75.2 Leak inspection using optical gas imaging and repairing any leaks found. (63.658(g)(2))

53.75.3 Visual inspection to determine the cause of the high benzene emissions and implementing repairs to reduce the level of emissions. (63.658(g)(3))

53.75.4 Employing progressively more frequent sampling, analysis and meteorology (*e.g.,* using shorter sampling periods for Methods 325A and 325B of appendix A of this part, or using active sampling techniques). (63.658(g)(4))

53.76 If, upon completion of the corrective action analysis and corrective actions such as those described in 63.658(g) (Condition 53.75), the Δc value for the next 14-day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 $\mu g/m^3$ or if all corrective action measures identified require more than 45 days to implement, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce fenceline concentrations below the action level, and a schedule for completion of these measures. The owner or operator shall submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the Δc value for the 14-day sampling period following the completion of the initial corrective action is greater than 9 $\mu g/m^3$ or, if no initial corrective actions were identified, no later than 60 days following the completion of the corrective action analysis required in 63.658(g) (Condition 53.75). (63.658(h))

53.77 An owner or operator may request approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources or onsite sources excluded under §63.640(g) according to the requirements in 63.658(i)(1) through (4). (63.640(i))

53.78 The owner or operator shall comply with the applicable recordkeeping and reporting requirements in §63.655(h) and (i). (63.658(j))

53.79 As outlined in §63.7(f), the owner or operator may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in 63.658(k)(1) through (7). (63.658(k))

Storage Vessel Provisions (63.660)

All tanks addressed in Section II of this permit (listed in the table in Section I, Condition 5.1) are subject to these requirements, except as noted below.

Tanks D-811, D-812, D-813, D-814, T81, T82, T90, T91, T92 and T400 are not considered storage vessels under MACT CC because they are pressure vessels.

Tank T7208 is part of the truck rack (R102). The truck loading rack at the Suncor facility is classified under SIC 5171, and is operated by Suncor Energy (U.S.A.)'s pipeline operation, as opposed to the Refinery (SIC Code 2911), therefore the requirements in 40 CFR Part 63 Subpart CC do not apply.

Tanks 17675 and 20529 and the pipeline receipt station sump are not considered storage vessels under MACT CC because they are less than 40 cubic meters.

Tank D-20 is not subject to the requirements to MACT CC because it is not associated with a process unit. In accordance with 63.640(c)(2) only storage vessels associated with a process unit are subject to MACT CC. Tank D-20 receives skimmed hydrocarbons (weathered reformate) from remediation system wells.

Tanks T60, T4501, T4502, T4503, T4504, T4507, T4508, T4514, T4515, T4516, T4517 and T4518 are not considered storage vessels under MACT CC because they are wastewater storage tanks. These tanks are subject to the wastewater treatment requirements in MACT CC.

53.80 Overlap with storage vessel regulations:

53.80.1 After the compliance dates specified in 63.640(h), a Group 2 storage vessel that is subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in 63.640(n)(8). After the compliance dates specified in 63.640(h), a Group 2 storage vessel that is subject to the provisions of 40 CFR part 61, subpart Y, is required to comply only with the requirements of 40 CFR part 61, subpart Y, except as provided in 63.740(n)(10). (63.640(n)(1)) The requirements in 40 CFR Part 60 Subpart Kb are included in Condition 48. No specific equipment has been identified at this facility that falls under this overlap category.

53.80.2 After the compliance dates specified in 63.640(h), a Group 1 storage vessel that is also subject to 40 CFR part 60, subpart Kb, is required to comply only with either 40 CFR part 60, subpart Kb, except as provided in 63.640(n)(8) or this subpart. After the compliance dates specified in 63.640(h), a Group 1 storage vessel that is also subject to 40 CFR part 61, subpart Y, is required to comply only with either 40 CFR part 61, subpart Y, except as provided in 63.640(n)(10) or this subpart. (63.640(n)(2)) The requirements in 40 CFR Part 60 Subpart Kb are included in Condition 48.

The following tanks fall under the provisions in 63.640(n)(2): T34, T55, T96, T97, T116, T775 and T2010.

53.80.3 After the compliance dates specified in 63.640(h), a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subpart K or Ka, is required to only comply with the provisions of this subpart. (63.640(n)(5))

The following tank falls under the provisions in 63.640(n)(5): T1

53.80.4 Storage vessels described by 63.640(n)(1) are to comply with 40 CFR part 60, subpart Kb, except as provided in 63.640(n)(8)(i) through (vi). Storage vessels described by 63.640(n)(2) electing to comply with part 60, subpart Kb of this chapter shall comply with subpart Kb except as provided in 63.640(n)(8)(i) through (viii). (63.640(n)(8))

53.80.4.1 Storage vessels that are to comply with §60.112b(a)(2) of subpart Kb are exempt from the secondary seal requirements of §60.112b(a)(2)(i)(B) during the gap measurements for the primary seal required by §60.113b(b) of subpart Kb. (63.640(n)(8)(i))

53.80.4.2 If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113b(b) of this chapter or to inspect the vessel to determine compliance with §60.113b(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in 63.640(h) for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW. (63.640(n)(8)(ii))

53.80.4.3 If a failure is detected during the inspections required by §60.113b(a)(2) or during the seal gap measurements required by §60.113b(b)(1), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator. (63.640(n)(8)(iii))

53.80.4.4 If an extension is utilized in accordance with 63.640(n)(8)(iii), the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §60.113b(a)(2) or §60.113b(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied. (63.640(n)(8)(iv))

53.80.4.5 Owners and operators of storage vessels complying with subpart Kb of part 60 may submit the inspection reports required by §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb as part of the periodic reports required by this subpart, rather than within the 30-day period specified in §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb. (63.640(n)(8)(v))

53.80.4.6 The reports of rim seal inspections specified in §60.115b(b)(2) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §60.113b(b)(4). Documentation of the inspections shall be recorded as specified in §60.115b(b)(3). (63.640(n)(8)(vi))

53.80.4.7 To be in compliance with §60.112b(a)(1)(iv) or (a)(2)(ii) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.*, pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the "no visible gap" requirement. (63.640(n)(8)(vii))

53.80.4.8 If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of §63.670 instead of the requirements referenced from part 60, subpart Kb of this chapter for that flare. (63.640(n)(8)(viii))

<u>Group 1 Storage Vessels:</u>

The following tanks are Group 1 storage vessels that do not meet the overlap provisions in Condition 53.80.2: T1, T58, T67, T70, T75, T77, T78, T80, T776, T777, and T778.

53.81 On and after the applicable compliance date for a Group 1 storage vessel located at a new or existing source as specified in §63.640(h) (Condition 53.3), the owner or operator of a Group 1 storage vessel storing liquid with a maximum true vapor pressure less than 76.6 kilopascals (11.1 pounds per square inch) that is part of a new or existing source shall comply with either the requirements in subpart WW or SS of this part according to the requirements in 63.660(a) through (i) and the owner or operator of a Group 1 storage vessel storing liquid with a maximum true vapor pressure greater than or equal to 76.6 kilopascals (11.1 pounds per square inch) that is part of a new or existing source shall comply with the requirements in subpart SS of this part according to the requirements in 63.660(a) through (i). (63.660)

The relevant requirements from 40 CFR Part 63 Subpart WW, National Emission Standards for Storage Vessels (Tanks)-Control Level 2, are as follows.

The requirements below reflect the rule language in 40 CFR Part 63 Subpart WW, as of the latest revisions to 40 CFR Part 63 Subpart WW published in the Federal Register on July 12, 2002. However, the permittee is subject to the latest version of 40 CFR Part 63 Subpart WW.

<u>Storage vessel control requirements (63.1062)</u>

53.81.1 For each storage vessel to which this subpart applies, the owner or operator shall comply with one of the requirements listed in 63.1062(a)(1) through (a)(3). (63.1062(a)).

53.81.1.1 Operate and maintain an IFR. (63.1062(a)(1))

53.81.1.2 Operate and maintain an EFR. (63.1062(a)(2))

53.81.1.3 Equivalent *requirements.* Comply with an equivalent to the requirements in 63.1062(a)(1) or (a)(2), as provided in §63.1064. (63.1062(a)(3))

<u>Floating roof requirements (62.1063)</u>

53.81.2 *Design requirements, Rim seals* (63.1063(a)(1))

53.81.2.1 Internal *floating roof.* An IFR shall be equipped with one of the seal configurations listed in 63.1063(a)(1)(i)(A) through (a)(1)(i)(C). (63.1063(a)(1)(i)).

53.81.2.2 *External floating roof.* An EFR shall be equipped with one of the seal configurations listed in 63.1063(a)(1)(ii)(A) and (a)(1)(ii)(B). (63.1063(a)(1)(ii))

53.81.3 *Deck fittings.* Openings through the deck of the floating roof shall be equipped as described in 63.1063(a)(2)(i) through (a)(2)(viii). (63.1063(a)(2))

53.81.3.1 Each opening except those for automatic bleeder vents (vacuum breaker vents) and rim space vents shall have its lower edge below the surface of the stored liquid. (63.1063(a)(2)(i))

53.81.3.2 Each opening except those for automatic bleeder vents (vacuum breaker vents), rim space vents, leg sleeves, and deck drains shall be equipped with a deck cover. The deck cover shall be equipped with a gasket between the cover and the deck. (63.1063(a)(2)(ii))

53.81.3.3 Each automatic bleeder vent (vacuum breaker vent) and rim space vent shall be equipped with a gasketed lid, pallet, flapper, or other closure device. (63.1063(a)(2)(iii))

53.81.3.4 Each opening for a fixed roof support column may be equipped with a flexible fabric sleeve seal instead of a deck cover. (63.1063(a)(2)(iv))

53.81.3.5 Each opening for a sample well or deck drain (that empties into the stored liquid) may be equipped with a slit fabric seal or similar device that covers at least 90 percent of the opening, instead of a deck cover. (63.1063(a)(2)(v))

53.81.3.6 Each cover on access hatches and gauge float wells shall be designed to be bolted or fastened when closed. (63.1063(a)(2)(vi))

53.81.3.7 Each opening for an unslotted guidepole shall be equipped with a pole wiper, and each unslotted guidepole shall be equipped with a gasketed cap on the top of the guidepole. (63.1063(a)(2)(vii))

53.81.3.8 Each opening for a slotted guidepole shall be equipped with one of the control device configurations specified in 63.1063(a)(2)(viii)(A) and (a)(2)(viii)(B). (63.1063(a)(2)(viii))

53.81.4 *Operational requirements.* The floating roof shall float on the stored liquid surface at all times, except when the floating roof is supported by its leg supports or other support devices (e.g., hangers from the fixed roof). (63.1603(b)(1))

53.81.5 When the storage vessel is storing liquid, but the liquid depth is insufficient to float the floating roof, the process of filling to the point of refloating the floating roof shall be continuous and shall be performed as soon as practical. (63.1063(b)(2))

53.81.6 Each cover over an opening in the floating roof, except for automatic bleeder vents (vacuum breaker vents) and rim space vents, shall be closed at all times, except when the cover must be open for access. (63.1063(b)(3))

53.81.7 Each automatic bleeder vent (vacuum breaker vent) and rim space vent shall be closed at all times, except when required to be open to relieve excess pressure or vacuum, in accordance with the manufacturer's design. (63.1063(b)(4))

53.81.8 Each unslotted guidepole cap shall be closed at all times except when gauging the liquid level or taking liquid samples. (63.1063(b)(5))

53.81.9 *Inspection frequency requirements—Internal floating roofs.* Internal floating roofs shall be inspected as specified in 63.1063(d)(1) before the initial filling of the storage vessel. Subsequent inspections shall be performed as specified in 63.1063(c)(1)(i) or (c)(1)(ii). (63.1063(c)(1))

53.81.9.1 Internal floating roofs shall be inspected as specified in 63.1063(c)(1)(i)(A) and (c)(1)(i)(B). (63.1063(c)(1)(i))

a. At least once per year the IFR shall be inspected as specified in 63.1063(d)(2). 63.1063(c)(1)(i)(A))

b. Each time the storage vessel is completely emptied and degassed, or every 10 years, whichever occurs first, the IFR shall be inspected as specified in 63.1063(d)(1. 63.1063(c)(1)(i)(B))

53.81.9.2 Instead of the inspection frequency specified in 63.1063(c)(1)(i), internal floating roofs with two rim seals may be inspected as specified in 63.1063(d)(1) each time the storage vessel is completely emptied and degassed, or every 5 years, whichever occurs first. (63.1063(c)(1)(ii))

53.81.10 *External floating roofs.* External floating roofs shall be inspected as specified in 63.1063(c)(2)(i) through (c)(2)(iv). (63.1063(c)(2))

53.81.10.1 Within 90 days after the initial filling of the storage vessel, the primary and secondary rim seals shall be inspected as specified in 63.1063(d)(3). (63.1063(c)(2)(i))

53.81.10.2 The secondary seal shall be inspected at least once every year, and the primary seal shall be inspected at least every 5 years, as specified in 63.1063(d)(3). (63.1063(c)(2)(ii))

53.81.10.3 Each time the storage vessel is completely emptied and degassed, or every 10 years, whichever occurs first, the EFR shall be inspected as specified in 63.1063(d)(1). (63.1063(c)(2)(iii))

53.81.10.4 If the owner or operator determines that it is unsafe to perform the floating roof inspections specified in 63.1063(c)(2)(i) and (c)(2)(ii), the owner or operator shall comply with the requirements of 63.1063(c)(2)(iv)(A) or (c)(2)(iv)(B). (63.1063(c)(2)(vi))

53.81.11 *Inspection procedure requirements.* Floating roof inspections shall be conducted as specified in 63.1063(d)(1) through (d)(3), as applicable. If a floating roof fails an inspection, the owner or operator shall comply with the repair requirements of 63.1063(e). (63.1063(d))

53.81.11.1 Floating roof (IFR and EFR) inspections shall be conducted by visually inspecting the floating roof deck, deck fittings, and rim seals from within the storage vessel. The inspection may be performed entirely from the top side of the floating roof, as long as there is visual access to all deck components specified in 63.1063(a). Any of the conditions described in 63.1063(d)(1)(i) through (d)(1)(v) constitutes inspection failure.

(63.1063(d)(1))

53.81.11.2 Tank-top inspections of IFR's shall be conducted by visually inspecting the floating roof deck, deck fittings, and rim seal through openings in the fixed roof. Any of the conditions described in 63.1063(d)(1)(i) through (d)(1)(iv) constitutes inspection failure. Identification of holes or tears in the rim seal is required only for the seal that is visible from the top of the storage vessel. (63.1063(d)(2))

53.81.11.3 Seal gap inspections for EFR's shall determine the presence and size of gaps between the rim seals and the wall of the storage vessel by the procedures specified in 63.1063(d)(3)(i). Any exceedance of the gap requirements specified in 63.1063(d)(3)(ii) and (d)(3)(iii) constitutes inspection failure. (63.1063(d)(3))

53.81.12 *Repair requirements.* Conditions causing inspection failures under paragraph (d) of this section shall be repaired as specified in 63.1063(e)(1) or (e)(2). (63.1063(e))

53.81.12.1 If the inspection is performed while the storage vessel is not storing liquid, repairs shall be completed before the refilling of the storage vessel with liquid. (63.1063(e)(1))

53.81.12.2 If the inspection is performed while the storage vessel is storing liquid, repairs shall be completed or the vessel removed from service within 45 days. If a repair cannot be completed and the vessel cannot be emptied within 45 days, the owner or operator may use up to 2 extensions of up to 30 additional days each. Documentation of a decision to use an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be completely emptied as soon as practical. (63.1063(e)(2))

<u>Alternative means of emission limitation (63.1064)</u>

53.81.13 An alternate control device may be substituted for a control device specified in §63.1063 if the alternate device has an emission factor less than or equal to the emission factor for the device specified in §63.1063. Requests for the use of alternate devices shall be made as specified in §63.1066(b)(3). Emission factors for the devices specified in §63.1063 are published in EPA Report No. AP-42, Compilation of Air Pollutant Emission Factors. (63.1064(a))

53.81.14 Tests to determine emission factors for an alternate device shall accurately simulate conditions under which the device will operate, such as wind, temperature, and barometric pressure. Test methods that can be used to perform the testing required in this paragraph include, but are not limited to, the methods listed in 63.1064(b)(1) through (b)(3). (63.1064(b))

53.81.15 An alternate combination of control devices may be substituted for any combination of rim seal and deck fitting control devices specified in §63.1063 if the alternate combination emits no more than the combination specified in §63.1063. The emissions from an alternate combination of control devices shall be determined using AP-42 or as specified in paragraph (b) of this section. The emissions from a combination of control devices specified in §63.1063 shall be determined using AP-42. Requests for the use of alternate devices shall be made as specified in §63.1066(b)(3). (63.1064(c))

Recordkeeping requirements (63.1065)

53.81.16 The owner or operator shall keep the records required in 63.1065(a) for as long as liquid is stored. Records required in 63.1065(b), (c) and (d) shall be kept for at least 5 years. Records shall be kept in such a manner that they can be readily accessed within 24 hours. Records may be kept in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche. (63.1065)

53.81.17 *Vessel dimensions and capacity.* A record shall be kept of the dimensions of the storage vessel, an analysis of the capacity of the storage vessel, and an identification of the liquid stored. (63.1065(a))

53.81.18 *Inspection results.* Records of floating roof inspection results shall be kept as specified in 63.1065(b)(1) and (b)(2). (63.1065(b))

53.81.18.1 If the floating roof passes inspection, a record shall be kept that includes the information specified in 63.1065(b)(1)(i) and (b)(1)(ii). If the floating roof fails inspection, a record shall be kept that includes the information specified in 63.1065(b)(1)(i) through (b)(1)(v). (63.1065(b)(1))

53.81.18.2 A record shall be kept of EFR seal gap measurements, including the raw data obtained and any calculations performed. (63.1065(b)(2))

53.81.19 *Floating roof landings.* The owner or operator shall keep a record of the date when a floating roof is set on its legs or other support devices. The owner or operator shall also keep a record of the date when the roof was refloated, and the record shall indicate whether the process of refloating was continuous. (63.1065(c))

53.81.20 An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or §63.1063(c)(2)(iv)(B) shall keep the documentation required by those paragraphs. (63.1065(d))

Reporting requirements (63.1066)

53.81.21 *Periodic reports.* Report the information specified in 63.1066b)(1) through (b)(4), as applicable, in the periodic report specified in the referencing subpart. (63.1066(b))

53.81.21.1 *Notification of inspection.* To provide the Administrator the opportunity to have an observer present, the owner or operator shall notify the Administrator at least 30 days before an inspection required by §§63.1063(d)(1) or (d)(3). If an inspection is unplanned and the owner or operator could not have known about the inspection 30 days in advance, then the owner or operator shall notify the Administrator at least 7 days before the inspection. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Administrator at least 7 days before the inspection. If a delegated State or local agency is notified, the owner or operator is not required to notify the Administrator. A delegated State or local agency may waive the requirement for notification of inspections. (63.1066(b)(1))

53.81.21.2 *Inspection results.* The owner or operator shall submit a copy of the inspection record (required in §63.1065) when inspection failures occur. (63.1066(b)(2))

53.81.21.3 *Requests for alternate devices.* The owner or operator requesting the use of an alternate control device shall submit a written application including emissions test results and an analysis demonstrating that the alternate device has an emission factor that is less than or equal to the device specified in §63.1063. (63.1066(b)(3))

53.81.21.4 Requests for extensions. An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or §63.1063(c)(2)(iv)(B) shall submit the documentation required by those paragraphs. 963.1066(b)(4))

53.82 As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A, WW, or SS of this part. The definitions of “Group 1 storage vessel” (paragraph (2)) and “Storage vessel” in §63.641 shall apply in lieu of the definition of “Storage vessel” in §63.1061. (63.660(a)) The methods in 63.660(a)(1) and (2) apply with respect to determining the annual average HAP content for purposes of determining group type.

53.83 A floating roof storage vessel complying with the requirements of subpart WW of this part may comply with the control option specified in 63.660(b)(1) and, if equipped with a ladder having at least one slotted leg, shall comply with one of the control options as described in 63.660(b)(2). If the floating roof storage vessel does not meet the requirements of §63.1063(a)(2)(i) through (a)(2)(viii) as of June 30, 2014, these requirements do not apply until the next time the vessel is completely emptied and degassed, or January 30, 2026, whichever occurs first. (63.660(b))

53.83.1 In addition to the options presented in §§63.1063(a)(2)(viii)(A) and (B) and 63.1064, a floating roof storage vessel may comply with §63.1063(a)(2)(viii) using a flexible enclosure device and either a gasketed or welded cap on the top of the guidepole. (63.660(b)(1))

53.83.2 Each opening through a floating roof for a ladder having at least one slotted leg shall be equipped with one of the configurations specified in 63.660(b)(2)(i) through (iii). (63.660(b)(2))

53.84 The following paragraphs apply to references 63.660(c), (f), (g) and (h).

53.85 For storage vessels previously subject to requirements in §63.646, initial inspection requirements in §63.1063(c)(1) and (c)(2)(i) (*i.e.*, those related to the initial filling of the storage vessel) or in §63.983(b)(1)(i)(A), as applicable, are not required. Failure to perform other inspections and monitoring required by this section shall constitute a violation of the applicable standard of this subpart. (63.660(e))

<u>Group 2 Storage Vessels</u>

The following tanks are Group 2 storage vessels that do not meet the overlap provisions in Condition 53.80.1: T2, T3, T52, T62, T94, T774, T2006, T3201, T3801, T57, T59, T64, T65, T66, T68, T69, T71, T72, T74, T76, T105, T112, T140, T142, T144, T145, T146, T147, T182, T191, T192, T193 and T194.

53.86 Each owner or operator subject to the storage vessel provisions in §63.646 shall keep the records specified in §63.123 of subpart G except as specified in 63.655(i)(1)(i) through (iv). Each owner or operator subject to the storage vessel provisions in §63.660 shall keep records as specified in 63.655(i)(1)(v) and (vi). (63.655(i)(1)) The requirements in 40 CFR Part 63 Subparts CC and WW that apply to Group 2 storage vessels are as follows:

53.86.1 Each owner or operator of a Group 2 storage vessel shall keep the records specified in §63.1065(a) of subpart WW. If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent for existing sources or 2 percent for new sources, a record of any data, assumptions, and procedures used to make this determination shall be retained. (63.655(i)(1)(vi))

53.86.2 *Vessel dimensions and capacity.* A record shall be kept of the dimensions of the storage vessel, an analysis of the capacity of the storage vessel, and an identification of the liquid stored. (63.1065(a))

Requirements for flare control devices (63.670)

The requirements in this section (63.670) and section 63.671 apply to the Plant 1 (main plant) flare (F1), the Plant 3 (Asphalt (AU)) flare (F2) and the GBR unit flare (F3)

On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to this subpart shall meet the applicable requirements for flares as specified in 63.670(a) through (q) and the applicable requirements in §63.671. The owner or operator may elect to comply with the requirements of 63.670(r) in lieu of the requirements in 63.670(d) through (f), as applicable. (63.670) Note that 63.670(a) is “reserved”.

53.87 Overlap of this subpart with other regulation for flares. On January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and subject to this subpart are required to comply only with the provisions specified in this subpart. Prior to January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and elect to comply with the requirements in §§63.670 and 63.671 are required to comply only with the provisions specified in this subpart. (63.640(s))

53.88 *Pilot flame presence.* The owner or operator shall operate each flare with a pilot flame present at all times when regulated material is routed to the flare. Each 15-minute block during which there is at least one minute where no pilot flame is present when regulated material is routed to the flare is a deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. The owner or operator shall monitor for the presence of a pilot flame as specified in 63.670(g). (63.670(b))

53.89 *Visible emissions.* The owner or operator shall specify the smokeless design capacity of each flare and operate with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when regulated material is routed to the flare and the flare vent gas flow rate is less than the smokeless design capacity of the flare. The owner or operator shall monitor for visible emissions from the flare as specified in 63.670(h). (63.670(c))

53.90 *Flare tip velocity*. For each flare, the owner or operator shall comply with either 63.670(d)(1) or (2), provided the appropriate monitoring systems are in-place, whenever regulated material is routed to the flare for at least 15-minutes and the flare vent gas flow rate is less than the smokeless design capacity of the flare. (63.670(d))

53.90.1 Except as provided in 63.670(d)(2), the actual flare tip velocity (V_{tip}) must be less than 60 feet per second. The owner or operator shall monitor V_{tip} using the procedures specified in 63.670(i) and (k). (63.670(d)(1))

53.90.2 V_{tip} must be less than 400 feet per second and also less than the maximum allowed flare tip velocity (V_{max}) as calculated according to the equation in 63.670(d)(2)). The owner or operator shall monitor V_{tip} using the procedures specified in 63.670(i) and (k) and monitor gas composition and determine NHV_{vg} using the procedures specified in 63.670(j) and (l). (63.670(d)(2))

53.91 *Combustion zone operating limits.* For each flare, the owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above 270 British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{cz} as specified in 63.670(m). (63.670(e))

53.92 *Dilution operating limits for flares with perimeter assist air.* Except as provided in 63.670(f)(1), for each flare actively receiving perimeter assist air, the owner or operator shall operate the flare to maintain the net heating value dilution parameter (NHVdil) at or above 22 British thermal units per square foot (Btu/ft^2) determined on a 15-minute block period basis when regulated material is being routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{dil} as specified in 63.670(n). (63.670(f))

53.92.1 If the only assist air provided to a specific flare is perimeter assist air intentionally entrained in lower and/or upper steam at the flare tip and the effective diameter is 9 inches or greater, the owner or operator shall comply only with the NHV_{cz} operating limit in 63.670(e) for that flare. (63.670(f)(1))

53.93 *Pilot flame* monitoring. The owner or operator shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present. (63.670(g))

53.94 *Visible emissions monitoring.* The owner or operator shall conduct an initial visible emissions demonstration using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A-7. The initial visible emissions demonstration should be conducted the first time regulated materials are routed to the flare. Subsequent visible emissions observations must be conducted using either the methods in 63.670(h)(1) or, alternatively, the methods in 63.670(h)(2). The owner or operator must record and report any instances where visible emissions are observed for more than 5 minutes during any 2 consecutive hours as specified in §63.655(g)(11)(ii). (63.670(h))

Note although the source installed a redundant video surveillance camera for subsequent visible emission observations, 63.670(h)(1) was included in the event that the camera is inoperable and observations must be conducted in accordance with these procedures.

53.94.1 At least once per day for each day regulated material is routed to the flare, conduct visible emissions observations using an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7. If at any time the owner or operator sees visible emissions while regulated material is routed to the flare, even if the minimum required daily visible emission monitoring has already been performed, the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7. If visible emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 CFR part 60, appendix A-7 must be extended to 2 hours or until 5-minutes of visible emissions are observed. Daily 5-minute Method 22 observations are not required to be conducted for days the flare does not receive any regulated material. (63.670(h)(1))

53.94.2 Use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The owner or operator must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be viewed at any time. (63.670(h)(2))

53.95 *Flare vent gas, steam assist and air assist flow rate monitoring.* The owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the flare as well as any flare supplemental gas used. Different flow monitoring methods may be used to measure different gaseous streams that make up the flare vent gas provided that the flow rates of all gas streams that contribute to the flare vent gas are determined. If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air and/or assist steam used with the flare. If pre-mix assist air and perimeter assist are both used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and perimeter assist air used with the flare. Flow monitoring system requirements and acceptable alternatives are provided in 63.670(i)(1) through (6). (63.670(i))

The source has installed flow monitors, except that assist air for the Plant 3 flare is monitored by continuously monitoring fan speed and using fan curves, so only 63.70(i)(1) and (5) are included.

53.95.1 The flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in standard conditions (*i.e.*, a temperature of 20 °C (68 °F) and a pressure of 1 atmosphere). (63.670(i)(1))

53.95.2 Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates. (63.670(i)(5))

53.96 *Flare vent gas composition monitoring.* The owner or operator shall determine the concentration of individual components in the flare vent gas using either the methods provided in 63.670(j)(1) or (2), to assess compliance with the operating limits in 63.670(e) and, if applicable, 63.670(d) and (f). Alternatively, the owner or operator may elect to directly monitor the net heating value of the flare vent gas following the methods provided in 63.670(j)(3) and, if desired, may directly measure the hydrogen concentration in the flare vent gas following the methods provided in 63.670(j)(4). The owner or operator may elect to use different monitoring methods for different gaseous streams that make up the flare vent gas using different methods provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined. (63.670(j))

The source is relying on calorimeters to directly measure heat value (63.670(j)(3) and is relying on the provisions in 63.670(j) for natural gas. The Plant 1 flare has a H2 monitor, so the provisions in 63.670(j)(4) applies.

53.96.1 Except as provided in 63.670(j)(5) and (6), the owner or operator shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHV_{vg} at standard conditions. (63.670(j)(3))

53.96.2 If the owner or operator uses a continuous net heating value monitor according to 63.670(j)(3), the owner or operator may, at their discretion, install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas. (63.670(j)(4))

53.96.3 Direct compositional or net heating value monitoring is not required for purchased ("pipeline quality") natural gas streams. The net heating value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the net heating value of any purchased natural gas stream can be assumed to be 920 Btu/scf. (63.670(j)(5))

53.97 *Calculation methods for cumulative flow rates and determining compliance with Vtip operating limits*. The owner or operator shall determine V_{tip} on a 15-minute block average basis according to the following requirements. (63.670(k))

Since the source is using flow monitors for flare vent gas, the requirements in 63.670(k)(2)(ii) were not included.

53.97.1 The owner or operator shall use design and engineering principles to determine the unobstructed cross sectional area of the flare tip. The unobstructed cross sectional area of the flare tip is the total tip area that vent gas can pass through. This area does not include any stability tabs, stability rings, and upper steam or air tubes because flare vent gas does not exit through them.(63.670(k)(1))

53.97.2 The owner or operator shall determine the cumulative volumetric flow of flare vent gas for each 15-minute block average period using the data from the continuous flow monitoring system required in 63.670(i) according to the following requirements, as applicable. If desired, the cumulative flow rate for a 15-minute block period only needs to include flow during those periods when regulated material is sent to the flare, but owners or operators may elect to calculate the cumulative flow rates across the entire 15-minute block period for any 15-minute block period where there is regulated material flow to the flare. (63.670(k)(2))

53.97.2.1 Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block average flow volumes. (63.670(k)(2)(i))

53.97.3 The 15-minute block average V_{tip} shall be calculated using the equation in 63.670(k)(3). (63.670(k)(3))

53.97.4 If the owner or operator chooses to comply with 63.670(d)(2), the owner or operator shall also determine the net heating value of the flare vent gas following the requirements in 63.670(j) and (l) and calculate V_{max} using the equation in paragraph (d)(2) of this section in order to compare V_{tip} to V_{max} on a 15-minute block average basis. (63.670(k)(4))

53.98 *Calculation methods for determining flare vent gas net heating value.* The owner or operator shall determine the net heating value of the flare vent gas (NHV_{vg}) based on the composition monitoring data on a 15-minute block average basis according to the following requirements. (63.670(l))

Since the source is using a calorimeter to monitor direct net heating value the requirements in 63.670(l)(1) and (6) do not apply and are not included.

53.98.1 If direct net heating value monitoring data are collected as provided in 63.670(j)(3) but a hydrogen concentration monitor is not used, the owner or operator shall use the direct output of the monitoring system(s) (in Btu/scf) to determine the NHV_{vg} for the sample. (63.670(l)(2))

53.98.2 If direct net heating value monitoring data are collected as provided in 63.670(j)(3) and hydrogen concentration monitoring data are collected as provided in 63.670(j)(4), the owner or operator shall use the following equation to determine NHV_{vg} for each sample measured via the net heating value monitoring system. (63.670(l)(3))

53.98.3 Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block averages. (63.670(l)(4))

53.98.4 When a continuous monitoring system is used as provided in 63.670(j)(1) or (3) and, if applicable, 63.670(j)(4), the owner or operator may elect to determine the 15-minute block average NHV_{vg} using either the calculation methods in 63.670(l)(5)(i) or the calculation methods in 63.670(l)(5)(ii). The owner or operator may choose to comply using the calculation methods in 63.670(l)(5)(i) for some flares at the petroleum refinery and comply using the calculation methods (l)(5)(ii) of this section for other flares. However, for each flare, the owner or operator must elect one calculation method that will apply at all times, and use that method for all continuously monitored flare vent streams associated with that flare. If the owner or operator intends to change the calculation method that applies to a flare, the owner or operator must notify the Administrator 30 days in advance of such a change. (63.670(l)(5))

53.98.5 If the owner or operator monitors separate gas streams that combine to comprise the total flare vent gas flow, the 15-minute block average net heating value shall be determined separately for each measurement location according to the methods in 63.670(l)(1) through (6) and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas. (63.670(l)(7))

53.99 *Calculation methods for determining combustion zone net heating value.* The owner or operator shall determine the net heating value of the combustion zone gas (NHV_{cz}) as specified in 673.670(m)(1) or (2), as applicable. (63.670(m))

The source is using the calculation method in 63.670(m)(1), so 63.670(m)(2) was not included.

53.99.1 Except as specified in 63.670(m)(2), determine the 15-minute block average NHV_{cz} based on the 15-minute block average vent gas and assist gas flow rates using the equation in 63.670(m)(1). For periods when there is no assist steam flow or premix assist air flow, $NHV_{cz} = NHV_{vg}$. (63.670(m)(1))

53.100 *Calculation methods for determining the net heating value dilution parameter.* The owner or operator shall determine the net heating value dilution parameter (NHV_{dil}) as specified in 63.670(n)(1) or (2), as applicable. (63.670(n))

The source is using the calculation method in 63.670(n)(1), so 63.670(n)(2) was not included.

53.100.1 Except as specified in 63.670(n)(2), determine the 15-minute block average NHV_{dil} based on the 15-minute block average vent gas and perimeter assist air flow rates using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated. (63.670(n)(1))

53.101 *Emergency flaring provisions.* The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall comply with the provisions in 63.670(o)(1) through (7). (63.670(o))

53.101.1 Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases. The flare management plan must include the information described in 63.670(o)(1)(i) through (vii). (63.670(o)(1))

53.101.2 Each owner or operator required to develop and implement a written flare management plan as described in 63.670(o)(1) must submit the plan to the Administrator as described in 63.670(o)(2)(i) through (iii). (63.670(o)(2))

53.101.3 The owner or operator of a flare subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each flow event that contains regulated material and that meets either the criteria in 63.670(o)(3)(i) or (ii). (63.670(o)(3))

53.101.3.1 The vent gas flow rate exceeds the smokeless capacity of the flare based on a 15-minute block average and visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event. (63.670(o)(3)(i))

53.101.3.2 The vent gas flow rate exceeds the smokeless capacity of the flare and the 15-minute block average flare tip velocity exceeds the maximum flare tip velocity determined using the methods in 63.670(d)(2). (63.670(o)(3)(ii))

53.101.4 A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a flare flow event meeting the criteria in 63.670(o)(3)(i) or (ii). Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 63.670(o)(4)(i) through (v). (63.670(o)(4))

53.101.5 Each owner or operator of a flare required to conduct a root cause analysis and corrective action analysis as specified in 63.670(o)(3) and (4) shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in 63.670(o)(5)(i) through (iii). (63.670(o)(5))

53.101.6 The owner or operator shall determine the total number of events for which a root cause and corrective action analyses was required during the calendar year for each affected flare separately for events meeting the criteria in 63.670(o)(3)(i) and those meeting the criteria in 63.670(o)(3)(ii). For the purpose of this requirement, a single root cause analysis conducted for an event that met both of the criteria in 63.670(o)(3)(i) and (ii) would be counted as an event under each of the separate criteria counts for that flare. Additionally, if a single root cause analysis was conducted for an event that caused multiple flares to meet the criteria in 63.670(o)(3)(i) or (ii), that event would count as an event for each of the flares for each criteria in 63.670(o)(3) that was met during that event. The owner or operator shall also determine the total number of events for which a root cause and correct action analyses was required and the analyses concluded that the root cause was a force majeure event, as defined in this subpart. (63.670(o)(6))

53.101.7 The following events would be a violation of this emergency flaring work practice standard. (63.670(o)(7))

53.101.7.1 Any flow event for which a root cause analysis was required and the root cause was determined to be operator error or poor maintenance. (63.670(o)(7)(i))

53.101.7.2 Two visible emissions exceedance events meeting the criteria in 63.670(o)(3)(i) that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment. (63.670(o)(7)(ii))

53.101.7.3 Two flare tip velocity exceedance events meeting the criteria in 63.670(o)(3)(ii) that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment. (63.670(o)(7)(iii))

53.101.7.4 Three visible emissions exceedance events meeting the criteria in 63.670(o)(3)(i) that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason. (63.670(o)(7)(iv))

53.101.7.5 Three flare tip velocity exceedance events meeting the criteria in 63.670(o)(3)(ii) that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason. (63.670(o)(7)(v))

53.102 *Flare* monitoring *records*. The owner or operator shall keep the records specified in §63.655(i)(9). (63.670(p))

53.103 *Reporting.* The owner or operator shall comply with the reporting requirements specified in §63.655(g)(11). (63.670(q))

53.104 *Alternative means of emissions limitation.* An owner or operator may request approval from the Administrator for site-specific operating limits that shall apply specifically to a selected flare. Site-specific operating limits include alternative threshold values for the parameters specified in 63.670(d) through (f) as well as threshold values for operating parameters other than those specified in 63.670(d) through (f). The owner or operator must demonstrate that the flare achieves 96.5 percent combustion efficiency (or 98 percent destruction efficiency) using the site-specific operating limits based on a performance evaluation as described in 63.670(r)(1). The request shall include information as described in 63.670(r)(2). The request shall be submitted and followed as described in 63.670(r)(3). (63.670(r))

Requirements for flare monitoring systems (63.671)

53.105 *Operation of CPMS*. For each CPMS installed to comply with applicable provisions in §63.670, the owner or operator shall install, operate, calibrate, and maintain the CPMS as specified in 63.671(a)(1) through (8). (63.671(a))

53.105.1 Except for CPMS installed for pilot flame monitoring, all monitoring equipment must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart. (63.671(a)(1))

53.105.2 The owner or operator shall ensure the readout (that portion of the CPMS that provides a visual display or record) or other indication of the monitored operating parameter from any CPMS required for compliance is readily accessible onsite for operational control or inspection by the operator of the source. (63.671(a)(2))

53.105.3 All CPMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period. (63.671(a)(3))

53.105.4 Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall operate all CPMS and collect data continuously at all times when regulated emissions are routed to the flare. (63.671(a)(4))

53.105.5 The owner or operator shall operate, maintain, and calibrate each CPMS according to the CPMS monitoring plan specified in 63.671(b). (63.671(a)(5))

53.105.6 For each CPMS except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in 63.671(c). (63.670(a)(6))

53.105.7 The owner or operator shall reduce data from a CPMS as specified in 63.671(d). (63.670(a)(7))

53.105.8 The CPMS must be capable of measuring the appropriate parameter over the range of values expected for that measurement location. The data recording system associated with each CPMS must have a resolution that is equal to or better than the required system accuracy. (63.670(a)(8))

53.106 *CPMS monitoring plan.* The owner or operator shall develop and implement a CPMS quality control program documented in a CPMS monitoring plan that covers each flare subject to the provisions in §63.670 and each CPMS installed to comply with applicable provisions in §63.670. The owner or operator shall have the CPMS monitoring plan readily available on-site at all times and shall submit a copy of the CPMS monitoring plan to the Administrator upon request by the Administrator. The CPMS monitoring plan must contain the information listed in 63.671(b)(1) through (5). (63.671(b))

53.106.1 Identification of the specific flare being monitored and the flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted). (63.671(b)(1))

53.106.2 Identification of the parameter to be monitored by the CPMS and the expected parameter range, including worst case and normal operation. (63.671(b)(2))

53.106.3 Description of the monitoring equipment, including the information specified in 63.671(b)(3)(i) through (vii). (63.671(b)(3))

53.106.4 Description of the data collection and reduction systems, including the information specified in 63.671(b)(4)(i) through (iii). (63.671(b)(4))

53.106.5 Routine quality control and assurance procedures, including descriptions of the procedures listed in 63.671(b)(5)(i) through (vi) and a schedule for conducting these procedures. The routine procedures must provide an assessment of CPMS performance. (63.671(b)(5))

53.107 *Out-of-control periods*. For each CPMS installed to comply with applicable provisions in §63.670 except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in 63.671(c)(1) and (2). (63.671(c))

53.107.1 A CPMS is out-of-control if the zero (low-level), mid-level (if applicable) or high-level calibration drift exceeds two times the accuracy requirement of table 13 of this subpart. (63.671(c)(1))

53.107.2 When the CPMS is out of control, the owner or operator shall take the necessary corrective action and repeat all necessary tests that indicate the system is out of control. The owner or operator shall take corrective action and conduct retesting until the performance requirements are below the applicable limits. The beginning of the out-of-control period is the hour a performance check (*e.g.*, calibration drift) that indicates an exceedance of the performance requirements established in this section is conducted. The end of the out-of-control period is the hour following the completion of corrective action and successful demonstration that the system is within the allowable limits. The owner or operator shall not use data recorded during periods the CPMS is out of control in data averages and calculations, used to report emissions or operating levels, as specified in 63.671(d)(3). (63.671(c)(2))

53.108 *CPMS data reduction*. The owner or operator shall reduce data from a CPMS installed to comply with applicable provisions in §63.670 as specified in 63.671(d)(1) through (3). (63.671(d))

53.108.1 The owner or operator may round the data to the same number of significant digits used in that operating limit. (63.671(d)(1))

53.108.2 Periods of non-operation of the process unit (or portion thereof) resulting in cessation of the emissions to which the monitoring applies must not be included in the 15-minute block averages. (63.671(d)(2))

53.108.3 Periods when the CPMS is out of control must not be included in the 15-minute block averages. (63.670(d)(3))

53.109 *Additional requirements for gas chromatographs.* For monitors used to determine compositional analysis for net heating value per §63.670(j)(1), the gas chromatograph must also meet the requirements of 63.671(e)(1) through (3). (63.671(e))

53.109.1 The quality assurance requirements are in table 13 of this subpart. (63.671(e)(1))

53.109.2 The calibration gases must meet one of the options in 63.671(e)(2)(i) or (ii). (63.671(e)(2))

53.109.3 If the owner or operator chooses to use a surrogate calibration gas under 63.671(e)(2)(ii), the owner or operator must comply with 63.671(e)(3)(i) and (ii). (63.671(e)(3))

54. 40 CFR Part 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

The FCCU (P103), SRUs (P101 and P102, routed to H-25 (tail gas incinerator)) and the catalytic reforming unit (P104), as well as any bypass lines associated with these units are subject to these requirements.

The requirements below reflect the current rule language as of the latest revisions to 40 CFR Part 63 Subpart UUU published in the Federal Register on November 19, 2020. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63 Subpart UUU.

The relevant requirements in 40 CFR Part 63 Subpart UUU include, but are not limited to the following:

What parts of my plant are covered by this subpart? (63.1562)

54.1 The affected sources are (63.1562(b):

54.1.1 The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (*i.e.*, the catalyst regeneration flue gas vent). (63.1562(b)(1)) P103 (FCC Regenerator) is the affected source, see Section II.22.

54.1.2 The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation. (63.1562(b)(2)) P104 (Catalytic Reforming Unit) is the affected source. P104 (Catalytic Reforming Unit) is the affected source, see Section II.16.

54.1.3 The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants that are associated with sulfur recovery. (63.1562(b)(3)) P101 (No. 1 Sulfur Recovery Unit), P102 (No. 2 Sulfur Recovery Unit), Tail Gas Unit and the Tail Gas Incinerator (H-25) are the affected source, see Section II.20.

54.1.4 Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart. (63.1562(b)(4)) There are no bypass lines associated with the Plants 1 and 3 catalytic cracking unit and catalytic reforming unit. There are two bypass lines associated with the SRUs, a tail gas unit bypass line and a sulfur pit (T-2005) bypass line.

54.2 This subpart does not apply to (63.1562(f)): Note that 62.1562(f)(1) thru (3) are not included as the refinery does not have such equipment or does not rely on a sulfur recovery unit not located at the refinery.

54.2.1 Equipment associated with bypass lines such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons. (63.1562(f)(4))

54.2.2 Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are subject to §63.670. (63.1562(f)(5))

When do I have to comply with this subpart? (63.1563)

54.3 You must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) as specified in paragraph (d)(1) or (2) of this section, as applicable. (63.1563(d))

54.3.1 For sources which commenced construction or reconstruction before June 30, 2014, you must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) (Conditions 54.5.5, 54.8.5 and 54.17.4) on or before August 1, 2017 unless an extension is requested and approved in accordance with the provisions in §63.6(i). After February 1, 2016 and prior to the date of compliance with the provisions in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) (Conditions 54.5.5, 54.8.5 and 54.17.4), you must comply with the requirements in §63.1570(c) and (d) (Conditions 54.25 and 54.26). (63.1563(d)(1))

54.4 You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart. (63.1563(f))

What are my requirements for metal HAP emissions from catalytic cracking units? (63.1564)

54.5 What emission limitations and work practice standards must I meet? You must: (63.1564(a))

54.5.1 Except as provided in 63.1564(a)(5), meet each emission limitation in table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter or is subject to §60.102a(b)(1) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for PM, you can choose from the six options in paragraphs (a)(1)(i) through (vi) of this section: (63.1564(a)(1))

As required by the Consent Decree (H-01-4430), the FCCU (P103) is subject to NSPS J for PM in 60.102. Therefore, the metal HAP emission limitations that apply to the FCCU (P103) are as follows:

54.5.1.1 PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and

54.5.1.2 Opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. (Table 1, item 1)

54.5.2 Comply with each operating limit in Table 2 of this subpart that applies to you. When a specific control device may be monitored using more than one continuous parameter monitoring system, you may select the parameter with which you will comply. You must provide notice to the Administrator (or other designated authority) if you elect to change the monitoring option. (63.1564(a)(2)) The operating limits in Table 2 that apply are as follows:

54.5.2.1 On and after August 1, 2017, maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than 20 percent. (Table 2, item 1)

54.5.2.2 During periods of startup, shutdown, or hot standby meet the requirements in §63.1564(a)(5 (Condition 54.5.5). (Table 2, item 10)

54.5.3 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) (Condition 54.40) and operate at all times according to the procedures in the plan. (63.1564(a)(3))

54.5.4 The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in 63.1564(a)(1) and (2) do not apply during periods of planned maintenance preapproved by the Division according to the requirements in 63.1575(j). (63.1564(a)(4))

54.5.5 On or before the date specified in §63.1563(d), you must comply with one of the two options in 63.1564(a)(5)(i) and (ii) during periods of startup, shutdown and hot standby (63.1564(a)(5)):

54.5.5.1 You can elect to comply with the requirements in 63.1564(a)(1) and (2), except catalytic cracking units controlled using a wet scrubber must maintain only the liquid to gas ratio operating limit (the pressure drop operating limit does not apply) (63.1564(a)(5)(i)); or

54.5.5.2 You can elect to maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second. (63.1564(a)(5)(ii))

54.5.5.3 *Hot standby* means periods when the catalytic cracking unit is not receiving fresh or recycled feed oil but the catalytic cracking unit is maintained at elevated temperatures, typically using torch oil in the catalyst regenerator and recirculating catalyst, to prevent a complete shutdown and cold restart of the catalytic cracking unit. (63.1579)

54.6 *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must (63.1564(b)): (Note that the requirements in (b)(4) were not included as it does not apply to sources subject to NSPS requirements.)

54.6.1 Install, operate, and maintain a continuous monitoring system(s) according to the requirements in 63.1572 and Table 3 of this subpart. (63.1564(b)(1)) The continuous monitoring system required by Table 3 are as follows:

54.6.1.1 You shall install, operate, and maintain a continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent. (Table 3, item 1)

54.6.1.2 If electing to comply with the operating limits in §63.1564(a)(5)(ii) during periods of startup, shutdown, or hot standby you shall install, operate and maintain a Continuous parameter monitoring system to measure and record the gas flow rate exiting the catalyst regenerator. (Table 3, item 12)

a. If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for gas flow rate. (Table 3, footnote 1)

54.6.2 Conduct a performance test for each catalytic cracking unit according to the requirements in §63.1571 and under the conditions specified in Table 4 of this subpart. (63.1564(b)(2)) The relevant requirements in Table 4 are as follows:

54.6.2.1 Select sampling port's location and the number of traverse ports using Method 1 or 1A in appendix A-1 to part 60 of this chapter. Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere. (Table 4, Item 1.a)

54.6.2.2 Determine velocity and volumetric flow rate using Method 2, 2A, 2C, 2D, or 2F in appendix A-1 to part 60 of this chapter, or Method 2G in appendix A-2 to part 60 of this chapter, as applicable. (Table 4, Item 1.b)

54.6.2.3 Conduct gas molecular weight analysis using Method 3, 3A, or 3B in appendix A-2 to part 60 of this chapter, as applicable. (Table 4, item 1.c)

54.6.2.4 Measure moisture content of the stack gas using Method 4 in appendix A-3 to part 60 of this chapter. (Table 4, item 1.d)

54.6.2.5 Measure PM emissions using Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min)). (Table 4, item 2.a)

54.6.2.6 Compute coke burn-off rate and PM emission rate (lb/1,000 lb of coke burn-off) using Equations 1, 2, and 3 of §63.1564 (if applicable). (Table 4, item 2.b)

54.6.2.7 Measure opacity of emissions using continuous opacity monitoring system. You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test and reduce the data to 6-minute averages. (Table 4, item 2.c)

54.6.3 Demonstrate initial compliance with each emission limitation that applies to you according to Table 5 of this subpart. (63.1564(b)(5)) The relevant provisions in Table 5 are as follows:

54.6.3.1 For the PM emission limit in Condition 54.5.1.1, you have demonstrated initial compliance if you have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. (Table 5, item 1)

54.6.3.2 For the opacity limit in Condition 54.5.1.2, you have demonstrated initial compliance if you have already conducted a performance test to demonstrate initial compliance with the NSPS and the average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. As part of your Notification of Compliance Status, you certify that your continuous opacity monitoring system meets the requirements in §63.1572. (Table 5, item 1)

54.6.4 Demonstrate initial compliance with the work practice standard in 63.1564(a)(3) of by submitting your operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status. (63.1564(b)(6))

54.6.5 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574. (63.1564(b)(7))

54.7 *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must (63.1564(c)):

54.7.1 Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart. (63.1564(c)(1)). The relevant provisions in Tables 6 and 7 that apply are as follows:

54.7.1.1 For the PM and opacity limits in Condition 54.5.1, you shall demonstrate continuous compliance by:

a. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator. (Table 6, item 1.a.1.i).

b. Conducting a performance test before August 1, 2017 or within 150 days of startup of a new unit and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit. (Table 6, item 1.a.ii).

c. Collecting the continuous opacity monitoring data for each catalyst regenerator vent according to §63.1572 and maintaining each 6-minute average at or below 30 percent, except that one 6-minute average during a 1-hour period can exceed 30 percent. (Table 6, item 1.a.iii).

54.7.1.2 For the operating limit in Condition 54.5.2.1, you shall demonstrate continuous compliance by collecting the continuous opacity monitoring data for each regenerator vent according to §63.1572 and maintain each 3-hour rolling average opacity of emissions no higher than 20 percent. (Table 7, item 1)

54.7.1.3 During periods of startup, shutdown, or hot standby, for the requirements in Condition 54.5.2.2 (inlet velocity limit), you shall demonstrate continuous compliance by meeting the requirements in §63.1564(c)(5). (Table 7, item 10)

54.7.2 Demonstrate continuous compliance with the work practice standard in 63.1564(a)(3) by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan. (63.1564(c)(2))

54.7.3 If you elect to comply with the alternative limit in 63.1564(a)(5)(ii) (Condition 54.5.2.2) during periods of startup, shutdown and hot standby, demonstrate continuous compliance on or before the date specified in §63.1563(d) by (63.1564(c)(5)):

54.7.3.1 Collecting the volumetric flow rate from the catalyst regenerator (in acfm) and determining the average flow rate for each hour. For events lasting less than one hour, determine the average flow rate during the event. (63.1564(c)(5)(i))

54.7.3.2 Determining the cumulative cross-sectional area of the primary internal cyclone inlets in square feet (ft^2) using design drawings of the primary (first-stage) internal cyclones to determine the inlet cross-sectional area of each primary internal cyclone and summing the cross-sectional areas for all primary internal cyclones in the catalyst regenerator or, if primary cyclones. If all primary internal cyclones are identical, you may alternatively determine the inlet cross-sectional area of one primary internal cyclone using design drawings and multiply that area by the total number of primary internal cyclones in the catalyst regenerator. (63.1564(c)(5)(ii))

54.7.3.3 Calculating the inlet velocity to the primary internal cyclones in feet per second (ft/sec) by dividing the average volumetric flow rate (acfm) by the cumulative cross-sectional area of the primary internal cyclone inlets (ft^2) and by 60 seconds/minute (for unit conversion). (63.1564(c)(5)(iii))

54.7.3.4 Maintaining the inlet velocity to the primary internal cyclones at or above 20 feet per second for each hour during the startup, shutdown, or hot standby event or, for events lasting less than 1 hour, for the duration of the event. (63.1564(c)(5)(iv))

What are my requirements for organic HAP emissions from catalytic cracking units? (63.1565)

54.8 *What emission limitations and work practice standards must I meet?* You must (63.1565(a)):

54.8.1 Except as provided in 63.1565(a)(5), meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in §60.103 of this chapter or is subject to §60.102a(b)(4) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for CO, you can choose from the two options in 63.1565(a)(1)(i) through (ii): (63.1565(a)(1))

As required by the Consent Decree (H-01-4430), the FCCU (P103) is subject to the NSPS for CO in 60.103 and so must meet the following emission limit in Table 8:

54.8.1.1 CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 parts per million volume (ppmv) (dry basis). (Table 8, item 1)

54.8.2 Comply with each site-specific operating limit in Table 9 of this subpart that applies to you. (63.1565(a)(2)) The provisions in Table 9 that apply are as follows:

54.8.2.1 During periods of startup, shutdown, or hot standby meet the requirements in §63.1565(a)(5) (Condition 54.8.5). (Table 9, item 3)

54.8.3 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1565(a)(3))

54.8.4 The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in 63.1565(a)(1) and (2) do not apply during periods of planned maintenance preapproved by the Division according to the requirements in 63.1575(j). (63.1565(a)(4))

54.8.5 On or before the date specified in §63.1563(d), you must comply with one of the two options in 63.1365(a)(5)(i) and (ii) during periods of startup, shutdown and hot standby (63.1565(a)(5)):

54.8.5.1 You can elect to comply with the requirements in 63.1565(a)(1) and (2); (63.1565(a)(5)(i)); or

54.8.5.2 You can elect to maintain the oxygen (O_2) concentration in the exhaust gas from your catalyst regenerator at or above 1 volume percent (dry basis) or 1 volume percent (wet basis with no moisture correction). (65.1565(a)(5)(ii))

54.8.5.3 *Hot standby* means periods when the catalytic cracking unit is not receiving fresh or recycled feed oil but the catalytic cracking unit is maintained at elevated temperatures, typically using torch oil in the catalyst regenerator and recirculating catalyst, to prevent a complete shutdown and cold restart of the catalytic cracking unit. (63.1579)

54.9 *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must: (63.1565(b)

54.9.1 Install, operate, and maintain a continuous monitoring system according to the requirements in 63.1572 and Table 10 of this subpart, except as provided for in 63.1565(b)(1)(i) through (iii). (63.1565(b)(1)) Note that the exceptions do not apply. The requirements in Table 10 that apply are as follows:

54.9.1.1 For the emission limit in Condition 54.8.1.1, you shall install, operate and maintain a continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent. (Table 10, item 1)

54.9.1.2 If electing to comply with the operating limits in §63.1565(a)(5)(ii) (Condition 54.8.5.2) during periods of startup, shutdown, or hot standby, you shall install, operate and maintain a continuous parameter monitoring system to measure and record the concentration by volume (wet or dry basis) of oxygen from each catalyst regenerator vent. If measurement is made on a wet basis, you must comply with the limit as measured (no moisture correction). (Table 10, item 3)

54.9.2 Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart. (63.1565(b)(4)) The provisions in Table 12 that apply are as follows:

54.9.2.1 For the CO emission limit in Condition 54.8.1.1, you have demonstrated initial compliance if you have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured CO emissions are less than or equal to 500 ppm (dry basis). As part of the Notification of Compliance Status, you must certify that your vent meets the CO limit. You are not required to conduct another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to conduct another performance evaluation to demonstrate initial compliance. (Table 12, item 1)

54.9.3 Demonstrate initial compliance with the work practice standard in 63.1565(a)(3) by submitting the operation, maintenance, and monitoring plan to the Division as part of your Notification of Compliance Status according to 63.1574. (63.1565(b)(5))

54.9.4 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.1574. (63.1565(b)(6))

54.10 *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must: (63.1565(c))

54.10.1 Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart. (63.1565(c)(1))

54.10.1.1 For the CO emission limit in Condition 54.8.1.1, you shall demonstrate continuous compliance by collecting the hourly average CO monitoring data according to §63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis). (Table 13, item 1).

54.10.1.2 During periods of startup, shutdown, or hot standby, for the requirements in Condition 54.8.5.2 (oxygen concentration), you shall demonstrate continuous compliance by collecting the hourly average oxygen concentration monitoring data according to §63.1572 and maintaining the hourly average oxygen concentration at or above 1 volume percent (dry basis). (Table 14, item 3)

54.10.2 Demonstrate continuous compliance with the work practice standard in 63.1565(a)(3) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1565(c)(2))

What are my requirements for organic HAP emissions from catalytic reforming units? (63.1566)

54.11 *What emission limitations and work practice standards must I meet?* You must: (63.1566(a))

54.11.1 Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in 63.1566(a)(1)(i) through (ii). (63.1566(a)(1)) Since the source will comply with the option in 63.1566(a)(1)(i), only that paragraph is included.

54.11.1.1 You can elect to vent emissions of total organic compounds (TOC) to a flare (Option 1). On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670. (63.1566(a)(1)(i))

54.11.2 Comply with each site-specific operating limit in Table 16 of this subpart that applies to you. (63.1566(a)(2)) The operating limit in Table 16 is as follows:

54.11.2.1 For a flare, during initial catalyst depressuring and purging operations on and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of §63.670. (Table 16, item 1)

54.11.3 Except as provided in 63.1566(a)(4), the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents. (63.1566(a)(3))

54.11.4 The emission limitations in tables 15 and 16 of this subpart do not apply to emissions from process vents during passive depressuring when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less or during active depressuring or purging prior to January 30, 2019, when the reactor vent pressure is 5 psig or less. On and after January 30, 2019, the emission limitations in tables 15 and 16 of this subpart do apply to emissions from process vents during active purging operations (when nitrogen or other purge gas is actively introduced to the reactor vessel) or active depressuring (using a vacuum pump, ejector system, or similar device) regardless of the reactor vent pressure.. (63.1566(a)(4))

54.11.5 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1566(a)(5))

54.12 *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must: (63.1566(b))

54.12.1 Install, operate, and maintain a continuous monitoring system(s) according to the requirements in 63.1572 and Table 17 of this subpart. (63.1566(b)(1)) The provisions in Table 17 that apply are as follows:

54.12.1.1 On and after January 30, 2019, you shall install and operate the monitoring systems required in §§63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame, or the monitoring systems required in §§63.670 and 63.671. (Table 17, item 1)

54.12.2 Conduct each performance test for a catalytic reforming unit according to the requirements in 63.1571 and under the conditions specified in Table 18 of this subpart. (63.1566(b)(2)) The provisions in Table 18 that apply are as follows:

54.12.2.1 You must conduct visible emission observations using Method 22 (40 CFR part 60, appendix A-7). On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, 2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test, or the requirements of §63.670. (Table 18, item 1.a)

54.12.2.2 You must determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity using 40 CFR 63.11(b)(6) through (8). On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670. (Table 18, item 1.b)

54.12.3 Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart. (63.1566(b)(3)) The relevant requirements in Table 18 are included in Condition 54.12.2.

54.12.4 Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart. (63.1566(b)(6)) The provisions in Table 19 that apply are as follows:

54.12.4.1 Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours. You have demonstrated initial compliance if on and after January 30, 2019, the flare meets the requirements of §63.670. Prior to January 30, 2019, visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes, or the flare meets the requirements of §63.670. (Table 19, item 1)

54.12.5 Demonstrate initial compliance with the work practice standard in 63.1566(a)(5) by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status. (63.1566(b)(7))

54.12.6 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574. (63.1566(b)(8))

54.13 *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must: (63.1566(c))

54.13.1 Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart. (63.1566(c)(1)) The requirements in Tables 20 and 21 that apply are as follows:

54.13.1.1 If you vent emissions from your process vent to a flare, you shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by, on and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours, or meeting the requirements of §63.670. (Table 20, item 1)

54.13.1.2 If you vent emissions from your process vent to a flare, you shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by, on and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, collecting flare monitoring data according to §63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of §63.670. (Table 21, item 1)

54.13.2 Demonstrate continuous compliance with the work practice standards in 63.1566(a)(3) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1566(c)(2))

What are my requirements for inorganic HAP emissions from catalytic reforming units? (63.1567)

54.14 *What emission limitations and work practice standards must I meet?* You must: (63.1567(a))

54.14.1 Meet each emission limitation in Table 22 to this subpart that applies to you. If you operate a catalytic reforming unit in which different reactors in the catalytic reforming unit are regenerated in separate regeneration systems, then these emission limitations apply to each separate regeneration system. These emission limitations apply to emissions from catalytic reforming unit process vents associated with the coke burn-off and catalyst rejuvenation operations during coke burn-off and catalyst regeneration. You can choose from the two options in 63.1567(a)(1)(i) through (ii): (63.1567(a)(1))

54.14.1.1 You can elect to meet an HCl concentration limit (Option 2). (63.1567(a)(1)(i)). The emission limit in Table 22 that the source is complying with is as follows:

a. For each existing semi-regenerative catalytic reforming unit during coke burn-off and catalyst rejuvenation emissions of hydrogen chloride (HCl) shall not exceed a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen. (Table 22, item 1)

54.14.2 Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits apply during coke burn-off and catalyst rejuvenation. (63.1567(a)(2))

54.14.2.1 For an internal scrubbing system or no control device (*e.g.*, hot regen system) meeting outlet HCl concentration limit, during coke burn-off and catalyst rejuvenation the daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test. (Table 23, item 2) The operating limit established in the October 2005 performance test is 27 ppmv HCl.

54.14.3 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedures in the plan. (63.1567(a)(3))

54.15 *How do I demonstrate initial compliance with the emission limitations and work practice standard?* You must: (63.1567(b))

54.15.1 Install, operate, and maintain a continuous monitoring system(s) according to the requirements in 63.1572 and Table 24 of this subpart. (63.1567(b)(1)) The requirements in Table 24 that apply are as follows:

54.15.1.1 If you use an internal scrubbing system or no control device (*e.g.*, hot regen system) to meet HCl outlet concentration limit, you shall install and operate a colormetric tube sampling system to measure the HCl concentration in the catalyst regenerator exhaust gas during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart. (Table 24, item 2)

54.15.2 Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and the conditions specified in Table 25 of this subpart. (63.1567(b)(2)) The provisions in Table 25 that apply are as follows:

54.15.2.1 Select sampling port location(s) and the number of traverse points using Method 1 or 1A (40 CFR part 60, appendix A), as applicable. If you elect to meet an applicable HCl outlet concentration limit, locate sampling sites at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series. If there is no control device, locate sampling sites at the outlet of the catalyst regenerator prior to any release to the atmosphere. (Table 25, item 1.a.(1))

54.15.2.2 Determine velocity and volumetric flow rate using Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable. (Table 25, item 1.b)

54.15.2.3 Conduct gas molecular weight analysis using Method 3, 3A, or 3B (40 CFR part 60, appendix A), as applicable. (Table 25, item 1.c)

54.15.2.4 Measure moisture content of the stack gas using Method 4 (40 CFR part 60, appendix A). (Table 25, item 1.d)

54.15.2.5 Measure the HCl concentration at the selected sampling locations using Method 26 or 26A (40 CFR part 60, appendix A). If your control device is a wet scrubber or internal scrubbing system, you must use Method 26A. (Table 25, item 1.d. (1), (2) and (4)).

a. For semi-regenerative and cyclic regeneration units, conduct the test during the coke burn-off and catalyst rejuvenation cycle, but collect no samples during the first hour or the last 6 hours of the cycle (for semi- regenerative units) or during the first hour or the last 2 hours of the cycle (for cyclic regeneration units). For continuous regeneration units, the test should be conducted no sooner than 3 days after process unit or control system start up.

b. Determine and record the HCl concentration corrected to 3 percent oxygen (using Equation 1 of §63.1567) for each sampling location for each test run.

c. Determine and record the average HCl concentration (corrected to 3 percent oxygen) and the average percent emission reduction, if applicable, for the overall source test from the recorded test run values.

54.15.3 Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart. (63.1567(b)(3)) The provisions in Table 25 that apply are as follows:

54.15.3.1 For an internal scrubbing system or no control device (e.g., hot regen system) meeting the HCl outlet concentration limit (30 ppmv (dry basis) corrected to 3 percent oxygen), measure and record the HCl concentration in the catalyst regenerator exhaust gas using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages. Determine and record the operating limit for HCl concentration using Equation 4 of §63.1567. (Table 25, item 3)

54.15.4 Use the equations in 63.1567(b)(4)(i) through (iv) to determine initial compliance with the emission limitations. (63.1567(b)(4))

54.15.5 Demonstrate initial compliance with each emission limitation that applies to you according to Table 26 of this subpart. (63.1567(b)(5)) The provisions in Table 26 that apply are as follows:

54.15.5.1 For each existing semi-regenerative catalytic reforming unit, complying with the HCl outlet concentration limit (30 ppmv (dry basis) corrected to 3 percent oxygen), you have demonstrated initial compliance if average emissions HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced to a concentration less than or equal to 30 ppmv (dry basis) corrected to 3 percent oxygen. (table 26, item 1)

54.15.6 Demonstrate initial compliance with the work practice standard in 63.1567(a)(3) by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status. (62.1567(b)(6))

54.15.7 Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574. (63.1567(b)(7))

54.16 *How do I demonstrate continuous compliance with the emission limitations and work practice standard?* You must: (63.1567(c))

54.16.1 Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart. (63.1567(c)(1)) The provisions in Tables 27 and 28 that apply are as follows:

54.16.1.1 For each existing semi-regenerative catalytic reforming unit, you shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by maintaining an HCl concentration no more than 30 ppmv (dry basis), corrected to 3 percent oxygen. (Table 27, item 1)

54.16.1.2 For an internal scrubbing system or no control device (e.g., hot regen system) meeting the HCl concentration limit (30 ppmv (dry basis) corrected to 3 percent oxygen), you shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by measuring and recording the HCl concentration at least 4 times during a regeneration cycle (equally spaced in time) or every 4 hours, whichever is more frequent, using a colormetric tube sampling system; calculating the daily average HCl concentration as an arithmetic average of all samples collected in each 24-hour period from the start of the coke burn-off cycle or for the entire duration of the coke burn-off cycle if the coke burn-off cycle is less than 24 hours; and maintaining the daily average HCl concentration below the applicable operating limit. (Table 28, item 2) Note that the applicable operating limit is 27 ppmv HCl.

54.16.2 Demonstrate continuous compliance with the work practice standard in 63.1567(a)(3) by maintaining records to document conformance with the procedures in you operation, maintenance and monitoring plan. (63.1567(c)(2))

What are my requirements for HAP emissions from sulfur recovery units? (63.1568)

54.17 *What emission limitations and work practice standard must I meet?* You must: (63.1568 (a))

54.17.1 Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in 60.104, you must meet the emission limitations for NSPS units. If your sulfur recovery unit isn't subject to the NSPS for sulfur oxides, you can choose from the options in 63.1568(a)(1)(i) through (ii). (63.1568(a)(1) The sulfur recovery units are subject to NSPS J, therefore must comply with NSPS J and is subject to the following emission limit:.

54.17.1.1 250 ppmv (dry basis) of sulfur dioxide (SO_2) at zero percent excess air, if you use an oxidation control system or if you use a reduction control system followed by incineration. (Table 29, item 1, excluding the phrase referencing equation 1 in 60.102a(f)(1)(i), since the units are not subject to NSPS Ja)

54.17.2 Meet each operating limit in Table 30 of this subpart that applies to you. (63.1568(a)(2)) The provisions in Table 30 that apply are as follows:

54.17.2.1 For startup and shutdown, if complying with 63.1568(a)(4)(ii) (Condition 54.17.4.2), on and after January 30, 2019, meet the applicable requirements of §63.670. Prior to January 30, 2019, meet the applicable requirements of either §63.11(b) or §63.670. (Table 30, item 5)

54.17.2.2 For startup and shutdown, if complying with 63.1568(a)(4)(iii) (Condition 54.17.4.3), maintain the hourly average combustion zone temperature at or above 1,200 degrees Fahrenheit and maintain the hourly average oxygen concentration in the exhaust gas stream at or above 2 volume percent (dry basis). (Table 39, item 6)

54.17.3 Prepare an operation, maintenance, and monitoring plan according to the requirements in 63.1574(f) and operate at all times according to the procedure in the plan. (63.1568(a)(3))

54.17.4 On or before the date specified in §63.1563(d), you must comply with one of the three options in 63.1568(a)(4)(i) through (iii) during periods of startup and shutdown. (63.1568(a)(4))

54.17.4.1 You can elect to comply with the requirements in 63.1568(a)(1) and (2). (63.1568(a)(4)(i))

54.17.4.2 You can elect to send any startup or shutdown purge gases to a flare. On and after January 30, 2019, the flare must meet the requirements of §63.670. (63.1568(a)(4)(ii), excluding language regarding requirements prior to January 30, 2019 as this is no longer relevant)

54.17.4.3 You can elect to send any startup or shutdown purge gases to a thermal oxidizer or incinerator operated at a minimum hourly average temperature of 1,200 degrees Fahrenheit in the firebox and a minimum hourly average outlet oxygen (O_2) concentration of 2 volume percent (dry basis). (63.1568(a)(4)(iii))

54.18 *How do I demonstrate initial compliance with the emission limitations and work practice standards?* You must (63.1568(b)):

54.18.1 Install, operate, and maintain a continuous monitoring system according to the requirements in 63.1572 and Table 31 of this subpart. (63.1568(b)(1)) The provisions in Table 31 that apply are as follows:

54.18.1.1 You shall install and operate a continuous emission monitoring system to measure and record the hourly average concentration of SO_2 (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air. (Table 31, item 1.a)

54.18.1.2 For startup and shutdown, if complying with 63.1568(a)(4)(ii) (Condition 54.17.4.2), On and after January 30, 2019, monitoring systems as specified in §§63.670 and 63.671. (Table 31, item 4, excluding language regarding requirements prior to January 30, 2019)

54.18.1.3 For startup and shutdown, if complying with 63.1568(a)(4)(iii) (Condition 54.17.4.3), continuous parameter monitoring systems to measure and record the firebox temperature of each thermal incinerator or oxidizer and the oxygen content (percent, dry basis) in the exhaust vent from the incinerator or oxidizer. (Table 31, item 5)

54.18.2 Demonstrate initial compliance with each emission limitation that applies to you according to Table 33 of this subpart. (63.1568(b)(5)) The provisions in Table 33 that apply are as follows:

54.18.2.1 You have demonstrated initial compliance if you have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of SO_2 emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance. (Table 33, item 1a, excluding the phrase regarding equation 1 of 60.102a(f)(1)(i), as these units are not subject to NSPS Ja)

54.18.3 Demonstrate initial compliance with the work practice standard in 63.1568(a)(3) by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status. (63.1568(b)(6))

54.18.4 Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574. (63.1568(b)(7))

54.19 *How do I demonstrate continuous compliance with the emission limitations and work practice standards?* You must (63.1568(c)):

54.19.1 Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart. (63.1568(c)(1)) The provisions in Tables 34 and 35 that apply are as follows:

54.19.1.1 Collecting the hourly average SO_2 monitoring data (dry basis, percent excess air; determining and recording each 12-hour rolling average concentration of SO_2; maintaining each 12-hour rolling average concentration of SO_2 at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO_2 greater than the applicable emission limitation in the semiannual compliance report required by §63.1575. (Table 34, item 1a, excluding the phrase regarding equation 1 of 60.102a(f)(1)(i), since these units are not subject to NSPS Ja)

54.19.1.2 If you are meeting the startup and shutdown requirements in 63.1568(a)(4)(ii) (Condition 54.17.4.2), you shall demonstrate continuous compliance by on and after January 30, 2019, complying with the applicable requirements of §63.670. (Table 35, item 4, excluding language regarding requirements prior to January 30, 2019)

54.19.1.3 If you are meeting the startup and shutdown requirements in 63.1568(a)(4)(iii) (Condition 54.17.4.3), you shall demonstrate continuous compliance by:

a. Collecting continuous (at least once every 15 minutes) and hourly average temperature monitoring data according to §63.1572; and maintaining the daily average firebox temperature at or above 1,200 degrees Fahrenheit. (Table 35, item 5.a)

b. Collecting continuous (at least once every 15 minutes) and hourly average O_2 monitoring data according to §63.1572; and maintaining the average O_2 concentration at or above 2 volume percent (dry basis). (Table 35, item 5.b)

54.19.2 Demonstrate continuous compliance with the work practice standard in 63.1568(a)(3) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1568(c)(2))

What are my requirements for HAP emissions from bypass lines? (63.1569)

54.20 *What work practice standards must I meet?* (63.1569(a))

54.20.1 You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in 63.1569(a)(1)(i) through (iv) (63.1569(a)(1)): Note that since the source is complying with the provisions in paragraphs (a)(i) and (a)(iv), only those paragraphs are included.

54.20.1.1 You can elect to install an automated system (Option 1). (63.1569(a)(1)(i)) This option applies to the T-2005 bypass line. The relevant provisions from Table 36 are as follows:

a. Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in the by bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere. (Table 36, item 1)

54.20.1.2 You can elect to vent to a control device (Option 4). (63.1569(a)(1)(iv)) This option applies to the TGU bypass line. The relevant provisions from Table 36 are as follows:

a. Vent the bypass line to a control device that meets the appropriate requirements in this subpart. (Table 36, item 1) The control device is a flare which is required to meet the requirements in § 63.670 on and after January 30, 2019.

54.20.2 You must prepare an operation, maintenance, and monitoring plan according to the requirements in §63.1574(f) and operate at all times according to the procedures in the plan. (63.1569(a)(3))

54.21 *How do I demonstrate initial compliance with the work practice standards?* You must (63.1569(b)):

54.21.1 If you elect the option in 63.1569(a)(1)(i), conduct each performance test for a bypass line according to the requirements in §63.1571 and under the conditions specified in Table 37 of this subpart. (63.1569(b)(1))

54.21.1.1 You shall record during the performance test for each type of control device whether the flow indicator, level recorder, or electronic valve position monitor was operating and whether flow was detected at any time during each hour of level the three runs comprising the performance test. (Table 37, item 1)

54.21.2 Demonstrate initial compliance with each work practice standard in Table 36 of this subpart that applies to you according to Table 38 of this subpart. (63.1569(b)(2)) The provisions in Table 38 that apply are as follows:

54.21.2.1 For option 1 (Condition 54.20.1.1), you have demonstrated initial compliance if the installed equipment operates properly during each run of the performance test and no flow is present in the line during the test. (Table 38, item 1)

54.21.2.2 For option 2 (Condition 54.20.1.2), you have demonstrated initial compliance if as part of the notification of compliance status, you certify that you installed the equipment, the equipment was operational by your compliance date, and you identify what equipment was installed. (Table 38, item 4)

54.21.3 Demonstrate initial compliance with the work practice standard in 63.1569(a)(3) by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status. (63.1569(b)(3))

54.21.4 Submit the notification of compliance status containing the results of the initial compliance demonstration according to the requirements in §63.1574. (63.1569(b)(4))

54.22 *How do I demonstrate continuous compliance with the work practice standards?* You must (63.1569(c)):

54.22.1 Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart. (63.1569(c)(1)) The provisions in Table 39 that apply are as follows:

54.22.1.1 For option 1 (Condition 54.20.1.1), monitoring and recording on a continuous basis or at least every hour whether flow is present in the bypass line; visually inspecting the device at least once every hour if the device is not equipped with a recording system that provides a continuous record; and recording whether the device is operating properly and whether flow is present in the bypass line. (Table 39, item 1)

54.22.1.2 For option 2 (Condition 54.20.1.2), Monitoring the control device according to appropriate subpart requirements. (Table 39, item 4)

54.22.1.3 For any option, recording and reporting the time and duration of any bypass. (Table 39, item 5)

54.22.2 Demonstrate continuous compliance with the work practice standard in 63.1569(a)(3) by complying with the procedures in your operation, maintenance, and monitoring plan. (63.1569(c)(2))

What are my general requirements for complying with this subpart? (63.1570)

54.23 You must be in compliance with all of the non-opacity standards in this subpart at all times. (63.1570(a))

54.24 You must be in compliance with the opacity and visible emission limits in this subpart at all times. (63.1570(b))

54.25 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 the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements 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. (63.1570(c))

54.26 During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log that documents the procedures used to minimize emissions from process and emissions control equipment according to the general duty in paragraph (c) of this section. (63.1570(d))

54.27 You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. These instances are deviations from the emission limitations and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.1575. (63.1570(f))

How and when do I conduct a performance test or other initial compliance demonstration? (63.1571)

54.28 *When must I conduct a performance test?* You must conduct initial performance tests and report the results by no later than 150 days after the compliance date specified for your source in §63.1563 and according to the provisions in §§63.7(a)(2) and 63.1574(a)(3). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup Notification of Compliance Status report due no later than 150 days after the test. You must conduct additional performance tests as specified in paragraphs (a)(5) and (6) of this section and report the results of these performance tests according to the provisions in §63.1575(f). (63.1571(a))

54.28.1 For each emission limitation or work practice standard where initial compliance is not demonstrated using a performance test, opacity observation, or visible emission observation, you must conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for your source in §63.1563. (63.1571(a)(1))

54.28.2 For each emission limitation where the averaging period is 30 days, the 30-day period for demonstrating initial compliance begins at 12:00 a.m. on the compliance date that is specified for your source in §63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for your source in §63.1563. (63.1571(a)(2))

54.28.3 *Periodic performance testing for PM or Ni.* Except as provided in 63.1571(a)(5)(i) and (ii), conduct a periodic performance test for PM or Ni for each catalytic cracking unit at least once every 5 years according to the requirements in Table 4 of this subpart. You must conduct the first periodic performance test no later than August 1, 2017 or within 150 days of startup of a new unit. (63.1571(a)(5)) The provisions in 63.1571(a)(5)(i) were not included as the FCCU does not have a PM CEMS.

54.28.3.1 Conduct a performance test annually if you comply with the emission limits in Item 1 (NSPS subpart J) or Item 4 (Option 1a) in Table 1 of this subpart and the PM emissions measured during the most recent performance source test are greater than 0.80 g/kg coke burn-off. (63.1571(a)(5)(ii))

54.28.4 *One-time performance testing for Hydrogen Cyanide (HCN).* Conduct a performance test for HCN from each catalytic cracking unit no later than August 1, 2017 or within 150 days of startup of a new unit according to the applicable requirements in 63.1571(a)(6)(i) and (ii). (63.1571(a)(6))

54.28.4.1 If you conducted a performance test for HCN for a specific catalytic cracking unit between March 31, 2011 and February 1, 2016, you may submit a request to the Administrator to use the previously conducted performance test results to fulfill the one-time performance test requirement for HCN for each of the catalytic cracking units tested according to the requirements in 63.1571(a)(6)(i)(A) through (D). (63.1571(a)(6)(i))

54.28.4.2 Unless you receive approval to use a previously conducted performance test to fulfill the one-time performance test requirement for HCN for your catalytic cracking unit as provided in 63.1571(a)(6)(i), conduct a performance test for HCN for each catalytic cracking unit no later than August 1, 2017 according to the requirements in 63.1571(a)(6)(ii)(A) thru (D) (63.1571(a)(6)(ii))

54.29 *What are the general requirements for performance test and performance evaluations?* You must (63.1571(b))

54.29.1 Performance tests shall be conducted according to the provisions of §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, you must operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. You must not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests. 63.1571(b)(1))

54.29.2 Except for opacity and visible emission observations, conduct three separate test runs for each performance test as specified in §63.7(e)(3). Each test run must last at least 1 hour. (63.1571(b)(2))

54.29.3 Conduct each performance evaluation according to the requirements in §63.8(e). (63.1571(b)(3))

54.29.4 Calculate the average emission rate for the performance test by calculating the emission rate for each individual test run in the units of the applicable emission limitation using Equation 2, 5, or 8 of §63.1564, and determining the arithmetic average of the calculated emission rates. (63.1571(b)(4))

54.30 *What procedures must I use for an engineering assessment?* You may choose to use an engineering assessment to calculate the process vent flow rate, net heating value, TOC emission rate, and total organic HAP emission rate expected to yield the highest daily emission rate when determining the emission reduction or outlet concentration for the organic HAP standard for catalytic reforming units. If you use an engineering assessment, you must document all data, assumptions, and procedures to the satisfaction of the applicable permitting authority. An engineering assessment may include the approaches listed in 63.1571(c)(1) through (c)(4). Other engineering assessments may be used but are subject to review and approval by the applicable permitting authority. (63.1571(c))

54.31 *Can I adjust the process or control device measured values when establishing an operating limit?* If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in 63.1571(d)(1) through (3). (63.1571(d)) Note that the provisions in 63.1571(d)(1) through (3) don’t apply as they are related to Ni limits.

54.31.1 Except as specified in 63.1571(d)(3), if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, total power and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values. (63.1571(d)(4))

54.32 *Can I change my operating limit?* You may change the established operating limit by meeting the requirements in 63.1571(e)(1) through (3). (63.1571(e)) Note that the provisions in 63.1571(e)(3) do not apply and are not included.

54.32.1 You may change your established operating limit for a continuous parameter monitoring system by doing an additional performance test, a performance test in conjunction with an engineering assessment, or an engineering assessment to verify that, at the new operating limit, you are in compliance with the applicable emission limitation. (63.1571(e)(1))

54.32.2 You must establish a revised operating limit for your continuous parameter monitoring system if you make any change in process or operating conditions that could affect control system performance or you change designated conditions after the last performance or compliance tests were done. You can establish the revised operating limit as described in 63.1571(e)(1). (63.1571(e)(2))

What are my monitoring installation, operation, and maintenance requirements? (63.1572)

54.33 You must install, operate, and maintain each continuous emission monitoring system according to the requirements in 63.1572(a)(1) through (4). (63.1572(a))

54.34 You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in 63.1572(b)(1) through (3). (63.1572(b))

54.35 Except for flare monitoring systems, you must install, operate, and maintain each continuous parameter monitoring system according to the requirements in 63.1572(c)(1) through (5). For flares, on and after January 30, 2019, you must install, operate, calibrate, and maintain monitoring systems as specified in §§63.670 and 63.671. Prior to January 30, 2019, you must either meet the monitoring system requirements in 63.1572(c)(1) through (5) or meet the requirements in §§63.670 and 63.671. (63.1572(c))

54.36 You must monitor and collect data according to the requirements in 63.1572(d)(1) and (2).

54.36.1 Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating. (63.1572(d)(1))

54.36.2 You may not use data recorded during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. (63.1572(d)(2))

What are my monitoring alternatives (63.1573)

What are the approved alternatives for measuring gas flow rate? (63.1573(a))

54.37 You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (*i.e.,* complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. You may also use this alternative to a continuous parameter monitoring system for the gas flow rate exiting the catalyst regenerator to determine inlet velocity to the primary internal cyclones as required in § 63.1564(c)(5) (Condition 54.7.3) regardless of the configuration of the catalytic regenerator exhaust vent downstream of the regenerator (*i.e.*, regardless of whether or not any other gas streams are introduced into the catalyst regeneration vent). Except, if you only use this alternative to demonstrate compliance with § 63.1564(c)(5) (Condition 54.7.3), you shall use the procedures in 63.1673(a)(1)(i) through (iii) for the performance test and for monitoring after the performance test. (63.1573(a)(1))

What notifications must I submit and when? (63.1574)

54.38 Except as allowed in 63.1574(a)(1) through (3), you must submit all of the notifications in §§63.6(h), 63.7(b) and (c), 63.8(e), 63.8(f)(4), 63.8(f)(6), and 63.9(b) through (h) that apply to you by the dates specified. (63.1574(a)) Note that the provisions in 63.1574(a)(1) do not apply and have not been included.

54.38.1 You must submit the notification of intent to conduct a performance test required in §63.7(b) at least 30 calendar days before the performance test is scheduled to begin (instead of 60 days). (60.1574(a)(2))

54.38.2 If you are required to conduct an initial performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to §63.9(h)(2)(ii). You can submit this information in an operating permit application, in an amendment to an operating permit application, in a separate submission, or in any combination. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just refer to the earlier submissions instead of duplicating and resubmitting the previously submitted information. (63.1574(a)(3)) Initial compliance demonstrations shall be submitted as required by 63.1574(a)(3)(i) and (ii).

54.39 You also must include the information in Table 42 of this subpart in your Notification of Compliance Status. (63.1574(d))

54.40 As required by this subpart, you must prepare and implement an operation, maintenance, and monitoring plan for each control system and continuous monitoring system for each affected source. The purpose of this plan is to detail the operation, maintenance, and monitoring procedures you will follow. (63.1574(f))

54.40.1 You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your permit under part 70 or 71 of this chapter, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan as submitted until the change is approved. (63.1574(f)(1))

54.40.2 Each plan must include, at a minimum, the information specified in 63.1574(f)(2)(i) through (xii). (63.1574(f)(2))

What reports must I submit and when? (63.1575)

54.41 You must submit each report in Table 43 of this subpart that applies to you. (63.1575(a)) The reports in Table 43 that apply are as follows:

54.41.1 You must submit a compliance report semiannually according to the requirements in §63.1575(b). If there are no deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in §63.1575(c) through (e). (Table 43, item 1)

54.41.2 You must submit performance test and CEMS performance evaluation data on and after February 1, 2016, that contains the information specified in §63.1575(k)(1), semiannually according to the requirements in §63.1575(b) and (f). (Table 43, item 2)

54.42 Unless the Administrator has approved a different schedule, you must submit each report by the date in Table 43 of this subpart and according to the requirements in 63.1575(b)(1) through (5). (63.1575(b)).

54.43 The compliance report must contain the information required in 63.1575(c)(1) through (4). (63.1575(c))

54.44 For each deviation from an emission limitation and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation or work practice standard in this subpart, the semiannual compliance report must contain the information in 63.1575(c)(1) through (3) and the information in 63.1575(d)(1) through (4). (63.1575(d))

54.45 For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in 63.1575(c)(1) through (3), in 63.1575(d)(1) through (3), and in 63.1575(e)(2) through (13). (63.1575(e))

54.46 You also must include the information required in 63.1575(f)(1) through (2) in each compliance report, if applicable. (63.1575(f))

54.46.1 A copy of any performance test or performance evaluation of a CMS done during the reporting period on any affected unit, if applicable. The report must be included in the next semiannual compliance report. The copy must include a complete report for each test method used for a particular kind of emission point tested. For additional tests performed for a similar emission point using the same method, you must submit the results and any other information required, but a complete test report is not required. A complete test report contains a brief process description; a simplified flow diagram showing affected processes, control equipment, and sampling point locations; sampling site data; description of sampling and analysis procedures and any modifications to standard procedures; quality assurance procedures; record of operating conditions during the test; record of preparation of standards; record of calibrations; raw data sheets for field sampling; raw data sheets for field and laboratory analyses; documentation of calculations; and any other information required by the test method. For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test, you must submit the results in accordance with 63,1575(k)(1)(i) by the date that you submit the compliance report, and instead of including a copy of the test report in the compliance report, you must include the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted in the compliance report. For performance evaluations of CMS measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation, you must submit the results in accordance with 63,1575(k)(2)(i) by the date that you submit the compliance report, and you must include the process unit where the CMS is installed, the parameter measured by the CMS, and the date that the performance evaluation was conducted in the compliance report. All other performance test and performance evaluation results (*i.e.*,those not supported by EPA's ERT) must be reported in the compliance report. (63.1575(f)(1))

54.46.2 Any requested change in the applicability of an emission standard (*e.g.*, you want to change from the PM standard to the Ni standard for catalytic cracking units or from the HCl concentration standard to percent reduction for catalytic reforming units) in your compliance report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements. (63.1575(f)(2))

54.47 You may submit reports required by other regulations in place of or as part of the compliance report if they contain the required information. (63.1575(g))

54.48 If the applicable permitting authority has approved a period of planned maintenance for your catalytic cracking unit according to the requirements in 63.1575(j), you must include the following information in your compliance report. (63.1575(i))

54.48.1 In the compliance report due for the 6-month period before the routine planned maintenance is to begin, you must include a full copy of your written request to the applicable permitting authority and written approval received from the applicable permitting authority. (63.1575(i)(1))

54.48.2 In the compliance report due after the routine planned maintenance is complete, you must include a description of the planned routine maintenance that was performed for the control device during the previous 6-month period, and the total number of hours during those 6 months that the control device did not meet the emission limitations and monitoring requirements as a result of the approved routine planned maintenance. (63.1575(i)(2))

54.49 *Electronic submittal of performance test and CEMS performance evaluation data.* For performance tests or CEMS performance evaluations conducted on and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, you must submit the results according to the procedures in 63.1575(k)(1) and (2). (63.1575(k))

54.49.1 Unless otherwise specified by this subpart, within 60 days after the date of completing each performance test as required by this subpart, you must submit the results of the performance tests following the procedure specified in either 63.1575(k)(1)(i) or (ii). (63.1575(k)(1))

54.49.2 Unless otherwise specified by this subpart, within 60 days after the date of completing each CEMS performance evaluation required by §63.1571(a) and (b), you must submit the results of the performance evaluation following the procedure specified in either 63.1575(k)(2)(i) or (ii). (63.1575(k)(2))

54.50 *Extensions to electronic reporting deadlines.* (63.1575(l))

54.50.1 If you are required to electronically submit a report through the Compliance and Emissions Data Reporting Interface (CEDRI) in the EPA's Central Data Exchange (CDX), and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description identifying the date(s) and time(s) the CDX or CEDRI were unavailable when you attempted to access it in the 5 business days prior to the submission deadline; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (63.1575(l)(1))

54.50.2 If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.*, hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.*, large scale power outage). If you intend to assert a claim of force majeure, you must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or caused a delay in reporting. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (63.1575(l)(2))

What records must I keep, in what form, and for how long? (63.1576)

54.51 You must keep the records specified in 63.1576(a)(1) through (3). (63.1576(a))

54.52 For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in 63.1576(b)(1) through (5). (63.1576(b))

54.53 You must keep the records in 63.6(h) for visible emission observations. (63.1576(c))

54.54 You must keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); Tables 20, 21, 27 and 28 of this subpart (for catalytic reforming units); Tables 34 and 35 of this subpart (for sulfur recovery units); and Table 39 of this subpart (for bypass lines) to show continuous compliance with each emission limitation that applies to you. (63.1576(d))

54.55 You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan. (63.1576(e))

54.56 You also must keep the records of any changes that affect emission control system performance including, but not limited to, the location at which the vent stream is introduced into the flame zone for a boiler or process heater. (63.1576(f))

54.57 Your records must be in a form suitable and readily available for expeditious review according to 63.10(b)(1). (63.1576(g))

54.58 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. (63.1576(h))

54.59 You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). You can keep the records offsite for the remaining 3 years. (63.1576(i))

What parts of the General Provisions apply to me? (63.1577)

54.60 Table 44 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. (63.1577) The requirements in Table 6 that apply to this facility, include bur are not limited to the following:

54.60.1 Prohibited activities and circumvention in §63.4.

54.60.2 <u>§63.6:</u> Operation and maintenance requirements in §63.6(e)(1)(iii), compliance with non-opacity standards in §63.6(f)(2) & (f)(3) (the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.1570(c) and subpart UUU specifies how and when the performance test results are reported) and compliance with opacity and visible emission standards in 63.6(h)(2)(iii), (h)(4) (applies to Method 22 (40 CFR part 60, appendix A-7) tests), (h)(6), (h)(7) (except paragraph (ii) and for paragraph (i), except the subpart specifies how and when the performance test results are reported) & (h)(8) (except subpart UUU specifies how and when performance test results are reported).

54.60.3 <u>§63.7:</u> The applicability and performance test date requirements in §63.7(a)(1) thru (4) (except under (a)(1) subpart UUU specifies specific test and demonstration procedures & (a)(2), except subpart UUU specifies that the results of initial performance tests must be submitted within 150 days after the compliance date), the notification of performance test in §63.7(b) (except it is due 30 days prior to the performance test), QA/QC requirements in §63.7(c), the performance testing facilities requirement in §63.7(d), the conduct of performance test requirements in §63.7(e)(2) thru (4) and data analysis, recordkeeping, reporting in §63.7(g) (except subpart UUU specifies how and when the performance test or performance evaluation results are reported, and §63.7(g)(2) is reserved and does not apply).

54.60.4 §63.8: The applicability requirements in §63.8(a)(1) thru (4) (except that in (a)(2) for a flare complying with 63.670, the cross-reference to 63.11 does not include 63.11(b)), conduct of monitoring requirements in §63.8(b), operation and continuous monitoring system requirements in §63.8(c)(1)) (excluding (c)(1)(i) and (iii)), (c)(2) thru (3) (except that subpart UUU specifies that for continuous parameter monitoring systems, operational status verification includes completion of manufacturer written specifications or installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately), (c)(4) thru (c)(8), the quality control program in §63.8(d)(1) thru (3), the performance evaluation in §63.8(e) (except subpart UUU specifies how and when the performance evaluation results are reported.) and data reduction in §63.8(g)(1) thru (4) (applies to continuous opacity monitoring system or continuous emission monitoring system).

54.60.5 §63.9: Notification of performance test in §63.9(e) (except that notification is required at least 30 days before test), notification of VE/opacity test in §63.9(f), continuous monitoring system notifications in §63.9(g) and notification of compliance status (except that subpart UUU specifies the notification is due no later than 150 days after compliance date, and except that the reference to §63.5(d)(1)(ii)(H) in §63.9(h)(5) does not apply).

54.60.6 §63.10: The general recordkeeping requirements in §63.10(b)(1), (b)(2)(iii) and (vi) thru (xiv), additional recordkeeping requirements for sources with continuous monitoring systems in §63.10(c)(1) thru (8) & (12 thru (14), the general reporting requirements in §63.10(d)(1), (3) & (4) and additional reporting requirements for sources with continuous monitoring systems in §63.10(e)(1), (2) & (4) (except that subpart UUU specifies how and when performance evaluation and performance test results are reported).

54.60.7 The control device and work practice requirements in §63.11, except that flares complying with §63.670 are not subject to the requirements of §63.11(b). Note that the requirements in 63.11(b) apply until January 30, 2019 (compliance date for flare requirements) unless the source opts to comply with the flare requirements prior to January 30, 2019.

55. 40 CFR Part 60 Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

The provisions in Subpart VVa are not directly applicable to the equipment at this facility but portions are applicable as specified in 40 CFR Part 60 Subpart GGGa.

Stayed Requirements: The definitions of "process unit" and "capital expenditure" in NSPS Subpart VVa have been stayed (see 60.480a(f) and 73 FR 31376, June 2, 2008). While the definitions of "process unit" and "capital expenditure are stayed owners or operations shall use the definition of "process unit" provided in §60.480a(f)(2)(i) in Subpart VVa and the definition of "capital expenditure" in §60.481 in Subpart VV. In addition 60.482-1a(g) and 60.482-11a were also stayed in the June, 2008 FR notice and so have not been included in the permit.

The requirements below reflect the current rule language as of the latest revisions to 40 CFR Part 60 Subpart VVa published in the Federal Register on June 2, 2008. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 60, Subpart VVa. The relevant requirements in 40 CFR Part 60 Subpart VVa include, but are not limited to the following:

Standards: General (60.482-1a)

55.1 Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment within 180 days of initial startup. (60.482-1a(a))

55.2 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. (60.482-1a(b))

55.3 An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§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 §60.484a. (60.482-1a(c)(1))

55.3.1 If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §60.482-2a, §60.482-3a, §60.482-5a, §60.482-6a, §60.482-7a, §60.482-8a, or §60.482-10a, an owner or operator shall comply with the requirements of that determination. (60.482-1a(c)(2))

55.4 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 §60.486a(e)(5). (60.482-1a(d))

55.5 Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§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 §60.482-1a(e)(1) through (3). (§60.182-1a(e))

55.6 If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the table in §60.482-1a(f)(1) instead of monitoring as specified in §§60.482–2a, 60.482–7a, and 60.483.2a. (§60.482-1a(f)(1))

55.6.1 Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in 60.482-1a(f)(1), provided the operating time of all such process units is considered. (60.482-1a(f)(2))

55.6.2 The monitoring frequencies specified in 60.482-1a(f)(1) are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator 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 60.482-1a(f)(3)(i) through (iv). (60.482-1a(f)(3))

55.7 60.482-1a(g) – This requirement has been stayed until further notice and is not include in the permit (see 73 FR 31376, June 2, 2008).

Standards: Standards Pumps in light liquid service (60.482-2a)

55.8 Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482–1a(c) and (f) and paragraphs (d), (e), and (f) of this section. 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 §60.482–1a(c) and §60.482-2a(d), (e), and (f). (§60.482-2a(a)(1))

55.9 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 §60.482–1a(f). (§60.482-2a(a)(2))

55.10 The instrument reading that defines a leak is specified in §60.482-2a(b)(1)(i) and (ii). (§60.482-2a(b))

55.11 If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either §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 §60.482-2a(b)(1)(i) or (ii), whichever is applicable. (§60.482-2a(b)(2))

55.12 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 §60.482–9a. (§60.482-2a(c)(1))

55.13 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 §60.382-2a(c)(2)(i) and (ii), where practicable. (§60.482-2a(c)(2))

55.14 Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of §60.482-2a(a), provided the requirements specified in §60.482-2a(d)(1) through (6) are met. (§60.482-2a(d))

55.15 Any pump that is designated, as described in §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 §60.482-2a(a), (c), and (d) if the pump (§60.482-2a(e)):

55.15.1 Has no externally actuated shaft penetrating the pump housing (60.482-2a(e)(1));

55.15.2 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 §60.485a(c) (60.482-2a(e)(2)); and

55.15.3 Is tested for compliance with 60.482-2a(e)(2) initially upon designation, annually, and at other times requested by the Administrator. (60.482-2a(e)(3))

55.16 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 §60.482–10a, it is exempt from §60.482-2a(a) through (e). ((§60.482-2a(f))

55.17 Any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of §60.482-2a(a) and (d)(4) through (6) if it meets the requirements in §60.482-2a(g)(1) and (2). (§60.482-2a(g))

55.18 Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of §60.482-2a(a)(2) and (d)(4), and the daily requirements of §60.482-2a(d)(5), provided that each pump is visually inspected as often as practicable and at least monthly. (§60.482-2a(h))

Standards: Compressors (60.482-3a)

55.19 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 §60.482–1a(c) and §60.482-3a(h), (i), and (j). (§60.482-3a(a))

55.20 Each compressor seal system as required in §60.482-3a(a) of this section shall be (§60.482-3a(b)):

55.20.1 Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

55.20.2 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 §60.482–10a; or

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

55.21 The barrier fluid system shall be in heavy liquid service or shall not be in VOC service. (§60.482-3a(c))

55.22 Each barrier fluid system as described in §60.482-3a(a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. (§60.482-3a(d))

55.23 Each sensor as required in §60.482-3a(d) shall be checked daily or shall be equipped with an audible alarm. (60.482-3a(e)(1))

55.24 The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both. (60.482-3a(e)(2))

55.25 If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under §60.482-3a(e)(2), a leak is detected. (60.482-3a(f))

55.26 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 §60.482–9a. (60.482-3a(g)(1))

55.27 A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. (60.482-3a(g)(2))

55.28 A compressor is exempt from the requirements of §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 §60.482–10a, except as provided in §60.482-3a(i). (60.482-3a(h))

55.29 Any compressor that is designated, as described in §60.486(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 §60.482-3a(a) through (h) if the compressor (60.482-3a(i)):

55.29.1 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 §60.485a(c) (60.482-3a(i)(1)); and

55.29.2 Is tested for compliance with §60.482-3a(i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator. (60.482-3a(i)(2))

55.30 Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from §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 §60.482-3a(a) through (e) and (h). (60.482-3a(j))

Standards: Pressure relief devices in gas/vapor service (60.482-4a)

55.31 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 §60.485a(c). (§60.482-4a(a)

55.32 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 §60.482–9a. (§60.482-4a(b)(1))

55.33 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 §60.485a(c). (§60.482-4a(b)(2))

55.34 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 §60.482–10a is exempted from the requirements of paragraphs (a) and (b) of this section. (§60.482-4a(c))

55.35 Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of 60.482-4a(a) and (b), provided the owner or operator complies with the requirements in §60.482-4a(d)(2). (§60.482-4a(d)(1))

55.36 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 §60.482–9a. (§60.482-4a(d)(2))

Standards: Sampling connection systems (60.482-5a)

55.37 Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482–1a(c) and 60.482-5a(c). (§60.482-5a(a))

55.38 Each closed-purge, closed-loop, or closed-vent system as required in §60.482-5a(a) shall comply with the requirements specified in 60.482-5a(b)(1) through (4). (§60.482-5a(b))

55.39 In-situ sampling systems and sampling systems without purges are exempt from the requirements of 60.482-5a(a) and (b). (§60.482-5a(c))

Standards: Open-ended valves or lines (60.482-6a)

55.40 Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1a(c) and §60.482-6a(d) and (e). (§60.482-6a(a)(1))

55.41 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. (§60.482-6a(a)(2))

55.42 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 paragraph (a) of this section at all other times. (§60.482-6a(b))

55.43 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 60.482-6a(a) at all other times. (§60.482-6a(c))

55.44 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 60.482-6a(a), (b), and (c). (§60.482-6a(d))

55.45 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 §60.482-6a(a) through (c) are exempt from the requirements of 60.482-6a(a) through (c). (§60.482-6a(e))

Standards: Valves in gas/vapor service and in light liquid service (60.482-7a)

55.46 Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with 60.482-7a(b) through (e), except as provided in 60.482-7a(f), (g), and (h), §60.482–1a(c) and (f), and §§60.483–1a and 60.483–2a. (§60.482-7a(a)(1))

55.47 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 60.482-7a(a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in 60.482-7a(f), (g), and (h) of this section, §60.482–1a(c), and §§60.483–1a and 60.483–2a. (§60.482-7a(a)(2))

55.48 If an instrument reading of 500 ppm or greater is measured, a leak is detected. (§60.482-7a(b))

55.49 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. (§60.482-7a(c)(1)(i))

55.50 As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator 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 owner or operator must keep records of the valves assigned to each subgroup. (§60.482-7a(c)(1)(ii))

55.51 If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months. (§60.482-7a(c)(2))

55.52 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 §60.482–9a. (§60.482-7a(d)(1))

55.53 A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. (§60.482-7a(d)(2))

55.54 First attempts at repair include, but are not limited to, the best practices specified in 60.482-7a(e)(1) through (4) where practicable (§60.482-7a(e))

55.55 Any valve that is designated, as described in §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 60.482-7a(a) if the valve (§60.482-7a(f)):

55.55.1 Has no external actuating mechanism in contact with the process fluid (60.482-7a(f)(1)),

55.55.2 Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c) (60.482-7a(f)(2)), and

55.55.3 Is tested for compliance with 60.482-7a(f)(2) initially upon designation, annually, and at other times requested by the Administrator. (60.482-7a(f)(3))

55.56 Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 60.482-7a (a) if (§60.482-7a(g)):

55.56.1 The owner or operator 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 60.482-7a(a) (60.482-7a(g)(1)), and

55.56.2 The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times. (60.482-7a(g)(2))

55.57 Any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of 60.482-7(a) if (§60.482-7a(h)):

55.57.1 The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface. (60.482-7a(h)(1))

55.57.2 The process unit within which the valve is located either becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator. (60.482-7a(h)(2))

55.57.3 The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year. (60.482-7a(h)(3))

Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service (60.482-8a)

55.58 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 owner or operator shall follow either one of the following procedures (§60.482-8a(a)):

55.58.1 The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of 60.482-8a(b) through (d). (§60.482-8a(a)(1))

55.58.2 The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection. (§60.482-8a(a)(2))

55.59 If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. (§60.482-8a(b))

55.60 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 §60.482–9a. (§60.482-8a(c)(1))

55.61 The first attempt at repair shall be made no later than 5 calendar days after each leak is detected. (§60.482-8a(c)(2))

55.62 First attempts at repair include, but are not limited to, the best practices described under §§60.482–2a(c)(2) and 60.482–7a(e). (§60.482-8a(d))

Standards: Delay of Repair (60.482-9a)

55.63 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. (§60.482-9a(a))

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

55.65 Delay of repair for valves and connectors will be allowed if (§60.482-9a(c)):

55.65.1 The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair (60.489-9a(c)(1)), and

55.65.2 When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a. (60.489-9a(c)(2))

55.66 Delay of repair for pumps will be allowed if (60.482-9a(d):

55.66.1 Repair requires the use of a dual mechanical seal system that includes a barrier fluid system (§60.482-9a(d)(1)), and

55.66.2 Repair is completed as soon as practicable, but not later than 6 months after the leak was detected. (§60.482-9a(d)(2))

55.67 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. (§60.482-9a(e))

55.68 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. (§60.482-9a(f))

Standards: Closed vent systems and control devices (60.482-10a)

55.69 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 this section. (§60.482-10a(a))

55.70 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. (§60.482-10a(b))

55.71 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. (§60.482-10a(c))

55.72 Flares used to comply with 40 CFR Part 60 Subpart VVa shall comply with the requirements of §60.18. (§60.482-10a(d))

55.73 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. (§60.482-10a(e))

55.74 Except as provided in 60.482-10a(i) through (k), each closed vent system shall be inspected according to the procedures and schedule specified in 60.482-10a(f)(1) and (2). (§60.482-10a(f))

55.75 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 60.482-10a(h). (§60.482-10a(g))

55.75.1 A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. (§60.482-10a(g)(1))

55.75.2 Repair shall be completed no later than 15 calendar days after the leak is detected. (§60.482-10a(g)(2))

55.76 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 owner or operator 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. (§60.482-10a(h))

55.77 If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 60.482-10a(f)(1)(i) and (f)(2). (§60.482-10a(i))

55.78 Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of 60.482-10a(f)(1)(i) and (f)(2) if they comply with the requirements specified in 60.482-10a(j)(1) and (2). (§60.482-10a(j))

55.78.1 The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with 60.482-10a(f)(1)(i) or (f)(2) (60.482-10a(j)(1)); and

55.78.2 The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times. (60.482-10a(j)(2))

55.79 Any parts of the closed vent system that are designated, as described in 60.482-10a(l)(2), as difficult to inspect are exempt from the inspection requirements of 60.482-10a(f)(1)(i) and (f)(2) if they comply with the requirements specified in 60.482-10a(k)(1) through (3). (§60.482-10a(k))

55.79.1 The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface (60.482-10a(k)(1)); and

55.79.2 The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect (60.482-10a(k)(2)); and

55.79.3 The owner or operator 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. (60.482-10a(k)(3))

55.80 The owner or operator shall record the information specified in 60.482-10a(l)(1) through (5). (§60.482-10a(l))

55.81 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. (§60.482-10a(m))

Standards: Connectors in gas/vapor service and in light liquid service (60.482-11a)

The requirements in 60.482-11a have been stayed until further notice and are not included in the permit (See 73 FR 31376, June 2, 2008).

Alternative standards for valves – allowable percentage of leaking valves (60.483-1a)

55.82 An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent. (60.483-1a(a))

55.83 The requirements in 60.483-1a(b)(1) through (3) shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking. (60.483-1a(b))

55.84 Performance tests shall be conducted in accordance with the requirements in 60.483-1a(c)(1) through (3).

55.85 Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h). (60.483-1a(d))

Alternative standards for valves – skip period leak detection and repair (60.483-2a)

55.86 An owner or operator may elect to comply with one of the alternative work practices specified in 60.483-2a(b)(2) and (3). (60.483-2a(a)(1))

55.87 An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a. (60.483-2a(a)(2))

55.88 An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7a. (60.483-2a(b)(1))

55.89 After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. (60.483-2a(b)(2))

55.90 After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. (60.483-2a(b)(3))

55.91 If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7a but can again elect to use this section. (60.483-2a(b)(4))

55.92 The percent of valves leaking shall be determined as described in §60.485a(h). (60.483-2a(b)(5))

55.93 An owner or operator must keep a record of the percent of valves found leaking during each leak detection period. (60.483-2a(b)(6))

55.94 A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve. (60.483-2a(b)(7))

Test methods and procedures (60.485a)

55.95 The test methods and procedures specified in §60.485 shall be followed.

Recordkeeping requirements (60.486a)

55.96 Records shall be kept as required by §60.486a.

Reporting requirements (60.487a)

55.97 Semi-annual reports shall be submitted as required by §60.487a.

56. 40 CFR Part 60, Subpart A - General Provisions

These requirements apply to those sources which are subject to 40 CFR Part 60 requirements (those sources are referred to this condition throughout the permit), with respect to those Part 60 requirements. Subpart A requirements include, but are not limited to, the following.

56.1 The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (60.7(b))

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

56.3 No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. (60.12)

57. Flare Requirements

These requirement apply to the truck rack flare (R102).

As provided for in Condition 53.87, on and after January 30, 2019, flares that are subject to the provisions in 40 CFR 60.18 and/or 63.11 and are subject to the requirements in 40 CFR Part 63 Subpart CC (Condition 53) are required to only comply with the requirements in 40 CFR Part 63 Subpart CC (Condition 53). The main plant flare (F1), the asphalt unit flare (F2) and the GBR unit flare (F3) are subject to the requirements in 40 CFR Part 63 Subpart CC and are no longer subject to the requirements in this Condition 57.

57.1 Flares shall be designed for and operated with no visible emissions as determined by methods specified in 60.18(f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. (60.18(c)(1))

57.2 Flares shall be operated with a flame present at all times, as determined by methods specified in 60.18(f). (60.18(c)(2)) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. (60.18(f)(2))

57.3 Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in 60.18(f)(3). (60.18(c)(3)(i))

57.4 Steam assisted and non-assisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in 60.18(f)(4), less than 18.3 m/sec (60 ft/sec), except as provided in 60.18(c)(4)(ii) and (iii). (60.18(c)(4)(i))

57.5 Air-assisted flares shall be designed and operated with an exit velocity as set forth in 60.18(c)(5).

57.6 Flares used to comply with this section shall be steam-assisted, air-assisted, or non-assisted. (60.18(c)(6))

57.7 Owners or operators of flares shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. (60.18(d))

57.8 Flares used to comply with the provisions of this subpart shall be operated at all times when emissions may be vented to them. (60.18(e))

57.9 Compliance with visible emission limitations in Condition 57.1 shall be monitored as follows:

These requirement apply to the truck rack flare (R102).

57.9.1 The permittee shall conduct daily visible emissions checks to qualitatively assess whether emissions are visible. Daily observations shall be conducted when materials are being loaded. Such visible emissions check shall last a minimum of six minutes. If no visible emissions are present during this observation, in the absence of credible evidence to the contrary, the flare will be considered in compliance with the visible emissions requirement in Condition 57.1.

57.9.2 If visible emissions are observed, actions shall be taken to reduce visible emissions to zero as soon as possible. If emissions cannot be reduced to zero, a two (2) hour observation shall be conducted in accordance with Method 22 within one half hour to determine if the flare is in compliance with the visible emissions requirement in Condition 57.1. If visible emissions are present for five minutes or less (total) during the two-hour observation, then the flare shall be deemed in compliance. If visible emissions are present for more than five minutes (total) during the two-hour observation, then the flare shall be deemed out of compliance with the above visible emissions requirement.

57.9.3 Subject to the provisions of C.R.S. §25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the visible emission requirement shall be considered to exist from the time a Method 22 reading is taken that shows the flare is out of compliance (as defined above) until a Method 22 reading is taken that shows the flare is in compliance (as defined above).

57.9.4 Daily visible emission observations are not required for the flare when the truck loading rack is not operated.

57.9.5 Records of the visible emission observations, any action(s) taken to reduce emissions to zero, the amount of time taken to reduce emissions to zero, and Method 22 readings shall be maintained and made available to the Division for review upon request.

58. Fuel Monitoring

The flow rate and heating value of the refinery fuel gas and natural gas (city gas) are measured with on-line flow meters and analyzers on a continuous basis. Flow rate measurements will be made from the flow meter associated with the applicable source. Heating value measurements (lab samples) will be made from a central sampling point that is representative of the entire fuel gas system. The higher (gross) heating value will be used in emission calculations and to determine the heat input of fired equipment. The continuous and weekly measurements will be used to satisfy the following requirements.

The fuel use by each source will be recorded, at a minimum, daily.

The heat value (HHV) of the refinery fuel gas will be analyzed at least once per week.

The heat value (HHV) of purchased natural gas (city gas) is assumed to be 1020 Btu/scf (based on the purchased natural gas heat value in 40 CFR Part 63 Subpart CC § 63.670(j)(5) and converted to HHV by dividing by 0.90).

Records of these measurements and the monthly and rolling twelve month fuel use shall be maintained on site and made available for Division inspection upon request.

In the event that a flow device becomes inoperable, fuel use data shall be determined as follows:

If the flow meter is inoperable for 12 hours or less, the average of the last recorded reading before the outage and the first recorded reading after the flow meter is operable again.

If the flow meter is inoperable for more than 12 hours, the design heat input rate for the unit.

Should the on-line BTU analyzer become inoperable, back-up laboratory GC analyzer data will be used instead.

59. Continuous Emission Monitoring and Continuous Opacity Monitoring Systems

The following requirements apply to the NO_X, SO_2 and CO continuous emission monitoring systems and the continuous opacity monitoring systems required for specific equipment as indicated in this permit.

59.1 Equipment and QA/QC Requirements

59.1.1 The Continuous Emission Monitoring Systems (CEMS) are subject to the applicable requirements in 40 CFR Part 60. These CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Subpart A § 60.13(d) and Appendix F and Condition 59.1.1.3. The monitoring systems shall meet the equipment, installation and performance specifications as follows:

59.1.1.1 The NO_X, SO_2 and diluents (O_2) monitors shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specifications 2 and 3.

59.1.1.2 The CO monitors shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A.

59.1.1.3 The NO_X, SO_2 and CO CEMS are subject to the following requirements:

a. Relative Accuracy Test Audits (RATAs): RATAs shall be conducted in the units (e.g., lb/MMBtu, ppm) of the emission limitation for all of the emission limitations that are applicable to the emissions unit. The RATAs for emissions units that have annual emission limits (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

b. The DAHS shall be able to record and manipulate the data in the units (e.g., lb/MMBtu, ppm) of the emission limitation and meet the reporting requirements for all of the emission limitations that are applicable to the emissions unit.

59.1.1.4 **Consent Decree Requirements:** The permittee shall install, certify, calibrate, maintain, and operate all CEMS required by the Consent Decree in accordance with the requirements of 40 CFR §§60.11, 60.13 and Part 60 Appendices A, B and F. With respect to 40 CFR Part 60, Appendix F, in lieu of the requirements of 40 CFR Part 60 Appendix F §5.1.1, 5.1.3 and 5.1.4, The permittee shall conduct either a Relative Accuracy Audit

("RAA") or a Relative Accuracy Test Audit ("RATA") once every twelve (12) calendar quarters, provided that a Cylinder Gas Audit is conducted each calendar quarter. These CEMS will be used to demonstrate compliance with emission limits. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7, III.B.7 and V.C.5 to include Consent Decree (H-01-4430) requirements for CEMS. Consent Decree (H-01-4430), Paragraph 202, language related to CEMS)

59.1.2 The Continuous Opacity Monitoring Systems (COMS) are subject to the following requirements:

59.1.2.1 The COMS are subject to the applicable requirements in 40 CFR Part 60. Each continuous opacity monitoring system shall meet the design, installation, equipment and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

59.1.2.2 The permittee shall install, certify, calibrate, maintain, and operate all COMS required by the Consent Decree in accordance with the requirements of 40 CFR §§60.11, 60.13 and Part 60 Appendices A and B. These COMS will be used to demonstrate compliance with emission limits. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7, III.B.7 and V.C.5 to include Consent Decree (H-01-4330) requirements for COMS. Consent Decree (H-01-4330), paragraph 202)

59.1.3 Quality assurance/quality control plans shall be prepared for the continuous emission monitoring systems in accordance with the applicable requirements in 40 CFR Part 60, Appendix F. The quality assurance/quality control plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

59.1.4 <u>40 CFR Part 60 Subpart A § 60.13(d) requirements:</u>

59.1.4.1 Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part, must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity. (60.13(d)(1))

59.1.4.2 Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation. (60.13(d)(2))

59.2 **General Provisions**

59.2.1 Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under Condition 59.1.4, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows (60.13(e)):

59.2.1.1 All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. (60.13(e)(1))

59.2.1.2 All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. (60.13(e)(2))

59.2.2 All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used. (60.13(f))

59.2.3 Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. (60.13(h)(1))

59.2.4 For continuous monitoring systems other than opacity, 1-hour averages shall be computed as specified in 60.13(h)(2)(i) through (ix), except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations (60.13(h)(2)).

59.2.5 All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit. (60.13(h)(3))

59.2.6 Alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring systems shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative continuous emission monitoring systems or continuous opacity monitoring systems must be certified in accordance with the requirements of 40 CFR Part 60. Guidelines for alternatives to monitoring procedures or requirements and relative accuracy (RA) tests are provided in § 60.13(i) and (j).

59.2.7 All test and monitoring equipment, methods, procedures and reporting shall be subject to the review and approval by the appropriate agency, either the Division or the U.S.EPA, depending on which agency is authorized to approve such alternative under applicable law, prior to any official use. The Division shall have the right to inspect such equipment, methods and procedures and data obtained at any time. The Division shall provide a witness(s) for any and all tests as Division resources permit (Colorado Regulation No. 3, Part C, Section V.C.).

59.3 **Recordkeeping Requirements**

59.3.1 Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (60.7(b))

59.3.2 Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, 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 this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as provided for in § 60.7(f). (60.7(f))

59.4 **Reporting Requirements**

59.4.1 Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see Condition 59.4.2) to the Division quarterly. All reports shall be postmarked by the 30th day following the end of each six-month period. (60.7(c), revised to stipulate quarterly reporting as the Division considers more frequent reporting is warranted for this facility, Colorado Regulation No. 3, Part C, Section V.C.). Written reports of excess emissions shall include the following information:

59.4.1.1 The magnitude of excess emissions computed in accordance with § 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. (60.7(c)(1))

59.4.1.2 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. (60.7(c)(2))

59.4.1.3 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. (60.7(c)(3))

59.4.1.4 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. (60.7(c)(4))

59.4.2 The summary report form shall contain the information and be in the format shown in figure 1 of § 60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at each affected facility. (60.7(d))

59.4.2.1 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 § 60.7(c) need not be submitted unless requested by the Division. (60.7(d)(1))

59.4.2.2 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 § 60.7(c) shall both be submitted. (60.7(d)(2))

59.4.3 Specific Reporting Requirements for NSPS Subpart Db (Boiler 4)

59.4.3.1 The owner or operator of any affected facility in any category listed in 60.49b(h)(1) or (2) is required to submit excess emission reports for any excess emissions that occurred during the reporting period. (60.49b(h))

a. Any affected facility that is subject to the NO_X standard of §60.44b (Condition 19.5.1), and that combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) (Condition 19.5.8) or steam generating unit operating conditions under §60.48b(g)(2). (60.49b(h)(2)(i) and (ii))

b. For purposes of §60.48b(g)(1) (Condition 19.5.8), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e) (Condition 19.5.5), that exceeds the applicable emission limits in §60.44b (Condition 19.5.1). (60.49b(h)(4))

59.4.3.2 The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under 60.49b(g) (Condition 19.5.10). (60.49b(i))

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

59.4.3.4 The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. (60.49b(w))

59.5 **Specific Provisions for NSPS Subpart Db (Boiler B-4)**

59.5.1 The CEMS required under 60.48b(b) (Condition 19.5.6) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments. (60.48b(c))

59.5.2 The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. (60.48b(e)) For affected facilities combusting natural gas, the span value for NO_X is 500 ppm. (60.48b(e)(2))

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

60. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to the FCCU, the Plant 1 WWTS (RTO and API headworks carbon canisters), the rail and truck racks, the Plant 3 and GBR flares, AIRS pt 615 AS/SVE system, AIRS pt 617 AS/SVE system, and the tank cleaning and degassing thermal oxidizer (P1DGTO) as indicated in Conditions 22.13, 23.13, 24.13, 25.17, 30.11, 31.12, 67.12 and 70.9 as follows:

60.1 For the **FCCU**, the permittee shall follow the CAM Plan provided in Appendix H of this permit. Excursions for purposes of reporting are as follows:

60.1.1 Except as provided for in Condition 60.1.2, any 3-hour period in which the average opacity exceeds 20%.

60.1.2 During periods of startup, shutdown and hot standby, a 3-hour period in which the opacity exceeds 20%, shall not be an excursion provided the provisions in Condition 54.5.5.2 (maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second) are met. Records shall be kept for those periods during startup, shutdown and hot standby when the 3-hour average opacity exceeds 20% but the inlet velocity is at or above 20 feet per second.

60.1.3 Hot standby is defined in Condition 54.5.5.3, as periods when the catalytic cracking unit is not receiving fresh or recycled feed oil but the catalytic cracking unit is maintained at elevated temperatures, typically using torch oil in the catalyst regenerator and recirculating catalyst, to prevent a complete shutdown and cold restart of the catalytic cracking unit. (63.1579)

60.2 For the **tank cleaning and degassing thermal oxidizer (TO)**, the permittee shall follow the CAM Plan provided in Appendix M of this permit. Excursions for purposes of reporting are as follows:

60.2.1 If the TO temperature monitoring system is not equipped with a continuous recorder, for purposes of reporting, excursions are as follows:

60.2.1.1 Any daily average temperature less than 1,400°F. The daily average is calculated in accordance with the CAM plan in Appendix M.

60.2.1.2 Failure to record the temperature during a clock hour when tank vapors are routed to the TO.

60.2.2 If the TO temperature monitoring system has a continuous recorder, an excursion is any day when the combustion zone temperature is less than 1,400°F when cleaning and degassing emissions are being routed to the TO. Only those periods when tank vapors are routed to the TO are used to determine the minimum daily temperature.

60.3 For **AIRS pt 615 and AIRS pt 617 AS/SVE Systems**, the permittee shall follow the CAM Plan provided in Appendix M of this permit. Excursions for purposes of reporting are as follows:

60.3.1 For AIRs pt 615 an excursion is defined as follows:

60.3.1.1 Any day in which vapors from the AS/SVE system are routed to the RTO and the daily recorded combustion zone temperature is less than 1,588 °F.

60.3.1.2 Any day in which vapors from the AS/SVE system are routed to the RTO and a combustion zone temperature is not recorded.

60.3.2 For AIRS pt 617 an excursion is defined as follows:

60.3.2.1 Any day in which vapors from the AS/SVE system are routed to the catalytic oxidizer and the daily recorded catalytic inlet temperature is less than 775 °F.

60.3.2.2 Any day in which vapors from the AS/SVE system are routed to the catalytic oxidizer and a catalyst inlet temperature is not recorded.

60.3.3 As provided for under the provisions of Condition 67.6.2, if either AIRS pt 615 or 617 can be operated in compliance with the emission limits in Condition 67.1 without the use of a control device, the CAM requirements will no longer apply to that equipment.

60.4 For the **Plant 1 WWTS**, the permittee shall follow the CAM Plan provided in Appendix M of this permit. Excursions for purposes of reporting are as follows:

60.4.1 For the Plant 1 WWTS RTO an excursion is defined as follows:

60.4.1.1 Any 3-hour period in which the temperature in the RTO combustion chamber is less than 1,573 °F.

60.4.2 For the API headworks carbon canisters an excursion is defined as follows:

60.4.2.1 Any daily breakthrough reading of 5 ppm benzene or more.

60.4.2.2 Any day in which vapors from the API headworks are routed to carbon canisters and a breakthrough reading is not conducted.

60.5 For the **rail loading rack (R101)**, the permittee shall follow the CAM plan provided in Appendix N of this permit. Excursions for purposes of reporting are as follows:

60.5.1 Any 6-hour period during which gasoline, jet fuel and/or distillate is loaded or ethanol is unloaded and the combustion zone temperature is less than 1,299 °F.

The 6-hour average is calculated in accordance with the CAM plan in Appendix N.

60.6 For the **truck loading rack (R102)**, the permittee shall follow the CAM plan provided in Appendix N of this permit. Excursions for purposes of reporting are defined as any period when vapors from gasoline and distillate loading are routed to the flare and:

60.6.1.1 The presence of a pilot flame is not detected, or

60.6.1.2 The pilot flame monitoring device is inoperable.

60.7 For the **Plant 3 (F2) and GBR (F3) Flares**, the permittee shall follow the CAM plan provided in Appendix N of this permit. Excursions for purposes of reporting are defined as follows:

60.7.1 Each 15-minute block during which there is at least one minute where no pilot flame is present when waste gas is routed to the flare. Excursions in different 15-minute blocks from the same event are considered separate excursions, or

60.7.2 Each 15-minute block period when waste gas is routed to the flare for at least 15-minutes and the net heating value of flare combustion zone gas (NHV_{cz}) is less than 270 Btu/scf, as calculated in accordance with the requirements of §63.670(m), or

60.7.3 A two-hour block period during which waste gas is routed to the flare, the flare vent gas flow rate is less than the smokeless design capacity and visible emissions are observed for a total of five (5) minutes or more, as determined in accordance with 40 CFR §63.670(h), or

60.7.4 Each 15-minute block period during which waste gas is routed to the flare for at least 15-minutes, the flare vent gas flow rate is less than the smokeless design capacity of the flare, and the flare tip velocity equals or exceeds the applicable maximum flare tip velocity in 40 CFR §63.670(d), or

60.7.5 For the Plant 3 flare only, each 15-minute block period during which waste gas is routed to the flare for at least 15-minutes, the flare is actively receiving perimeter assist air and NHV_{dil} is below 22 Btu/ft^2 as calculated in accordance with the requirements in 40 CFR §63.670(n), unless the conditions in 40 CFR §63.670(f)(1) are met.

60.8 Excursions shall be reported as required by Section IV, Conditions 21 and 22.d.of this permit.

60.9 Operation of Approved Monitoring

60.9.1 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 (40 CFR Part 64 §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.9.1.1 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 these CAM requirements, 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 (40 CFR Part 64 §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.9.2 Response to excursions or exceedances

60.9.2.1 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 (40 CFR Part 64 §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.9.2.2 Determination of whether the owner of 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 (40 CFR Part 64 §64.7(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.9.3 After approval of the monitoring required under the CAM requirements, 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 Division and, if necessary submit a proposed modification for this 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 (40 CFR Part 64 §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10 Quality Improvement Plan (QIP) Requirements

60.10.1 Based on the results of a determination made under the provisions of Condition 60.9.2.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64 §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64 §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.3 The QIP 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:

60.10.3.1 Improved preventative maintenance practices (40 CFR Part 64 §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.3.2 Process operation changes (40 CFR Part 64 §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.3.3 Appropriate improvements to control methods (40 CFR Part 64 §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64 §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 60.10.3.1 through 60.10.3.4 above) (40 CFR Part 64 §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division 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 (40 CFR Part 64 §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 60.9.2.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

60.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64 §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

60.10.5.2 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 (40 CFR Part 64 §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.10.6 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 federal clean air act (40 CFR Part 64 §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.11 Reporting and Recordkeeping Requirements

60.11.1 <u>Reporting Requirements:</u> The reports required by Section IV, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

60.11.1.1 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) ((40 CFR Part 64 §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

60.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 60.10 of this permit. 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 (40 CFR Part 64 §64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section IV, Condition 22.a. through c.

60.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 60.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 §64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.11.2.2 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 (40 CFR Part 64 §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.12 Savings Provisions

60.12.1 Nothing in these CAM requirements shall 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 federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64 §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64 §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

60.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64 §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

61. Reserved

61.1

62. Reserved

62.1

63. 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants from Industrial, Commercial, and Institutional Boilers and Process Heaters

Except for H-21, all boilers and process heaters addressed in Section II of this permit are subject to these requirements.

H-21 does not meet the definition of a process heater in §63.7575 since the combustion gases from H-21 come into direct contact with the process materials of the FCCU regenerator, therefore H-21 is not subject to the requirements in Subpart DDDDD.

Note that H-2410 is considered a new unit and all other units are considered to be existing units. (Changes made to H-1716 and H-1717 with the ULSD project do not meet the definition of reconstruction). All process heaters and boilers except H-13, H-16, H-18 and H-33 are over 10 MMBtu/hr. There are no process heater and boilers listed in Section II of the permit that are less than 5 MMBtu/hr.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63 Subpart DDDDD published in the Federal Register on December 28, 2020. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart DDDDD.

Please note that proposed revisions to 40 CFR Part 63 Subpart DDDDD were published in the Federal Register on August 24, 2020 to amend several numeric emission limits and set compliance dates for those limits, to address CO as a surrogate for organic HAPs and to make technical corrections. Therefore, the requirements below may change in the future.

When do I have to comply with this subpart? (63.7495)

63.1 If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later. (63.7496(a))

63.2 If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i). (63.7495(b))

63.3 You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart. (63.7495(d))

What emission limitations, work practice standards, and operating limits must I meet? (63.7500)

63.4 You must meet the requirements in §63.7500(a)(1) through (3), except as provided in §63.7500(b) through (e). You must meet these requirements at all times the affected unit is operating except as provided for in §63.7500(f). (63.7500(a)). Note that the requirements in §63.7500(a)(2) do not apply to these units so they have not been included in the permit.

63.5 You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. (63.7500(a)(1)) These emission units are not subject to the emission limitations in Tables 1 and 2 or the alternative emission limitations in Tables 11 through 13. The work practice standards in Table 3 that apply to these units are as follows:

63.5.1 For a new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in the gas 1 subcategory you must conduct a tune-up of the boiler or process heater every five years as specified in §63.7540. (Table 3, item 1)

63.5.2 For a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in the gas 1 subcategory you must conduct a tune-up of the boiler or process heater biennially as specified in §63.7540. (Table 3, item 2)

63.5.3 For a new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater you must conduct a tune-up of the boiler or process heater annually as specified in §63.7540. (Table 3, item 3)

63.5.4 For an existing boiler or process heater located at a major source facility you must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 (Condition 63.2) that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items 63.5.4.1 to 63.5.4.5 appropriate for the on-site technical hours listed in §63.7575. (Table 3, item 4) The energy assessment must include the following:

63.5.4.1 A visual inspection of the boiler or process heater system.

63.5.4.2 An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.

63.5.4.3 An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.

63.5.4.4 A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.

63.5.4.5 A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.

63.5.4.6 A list of cost-effective energy conservation measures that are within the facility's control.

63.5.4.7 A list of the energy savings potential of the energy conservation measures identified.

63.5.4.8 A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

63.6 At all times, you must operate and maintain any affected source (as defined in §63.7490), 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 that 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. (63.7500(a)(3))

63.7 As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section. (63.7500(b))

63.8 Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart. (63.7500(e))

What are my initial compliance requirements and by what date must I conduct them (63.7510)

63.9 For existing affected sources (as defined in §63.7490), you must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495. (63.7510(e))

63.10 For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d). (63.7510(g))

63.11 For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in §63.7495. (63.7510(j))

When must I conduct subsequent performance tests, fuel analyses, or tune-ups? (63.7515)

63.12 If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later. (63.7515(d))

63.13 You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up. (63.7515(g))

How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards? (63.7530)

63.14 You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended. (63.7530(e))

63.15 You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e). (63.7530(f))

How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards? (63.7540)

63.16 If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio. (63.7540(a)(10))

63.16.1 As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. 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 (63.7540(a)(10)(i));

63.16.2 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 (63.7540(a)(10)(ii));

63.16.3 Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection (63.7540(a)(10)(iii));

63.16.4 Optimize total emissions of CO. This optimization should be consistent with the manufacturer’s specifications, if available, and with any NO_X requirement to which the unit is subject (63.7540(a)(10)(iv));

63.16.5 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 (63.7540(a)(10)(v)); and

63.16.6 Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section. (63.7540(a)(10)(vi))

63.17 If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section (Condition 63.18)), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section (Conditions 63.16.1 through 63.16.6) to demonstrate continuous compliance. (63.7540(a)(11))

63.18 If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section (Conditions 63.16.1 through 63.16.6) to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) (Condition 63.16.1) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up. (63.7540(a)(12))

63.19 If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. (63.7540(a)(13))

What notifications must I submit and when? (63.7545)

63.20 You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified. (63.7545(a)) For the units addressed in this permit the requirement notifications are the initial notification (§63.9(b)) and the notification of compliance status (§63.9(h)).

63.21 As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013, or no later than 120 days after the source becomes subject to this subpart, whichever is later. (63.7545(b))

63.22 If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b). (63.7545(e)) The Notification of Compliance Status for the affected sources at this facility shall include the information specified in paragraphs (e)(1) and (8).

What reports must I submit and when? (63.7550)

63.23 You must submit each report in Table 9 to this subpart that applies to you. (63.7550(a))

63.24 For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report. (63.7550(b))

63.25 If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater. (63.7550(c)(1))

63.26 You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. (63.7550(h)(3))

What records must I keep? (63.7555)

63.27 You must keep the following records:

63.27.1 A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual [or annual, biennial or every five years, as applicable] compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv). (63.7555(a)(1))

63.27.2 Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii). (63.7555(a)(2))

In what form and how long must I keep my records? (63.7560)

63.28 Records shall be kept in the form and for the duration specified in §63.7560.

What parts of the General Provisions apply to me? (63.7565)

63.29 Table 10 of 40 CFR Part 63 Subpart DDDDD shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. (63.7565) These requirements include but are not limited to the following:

63.29.1 Prohibited activities in §63.4.

63.29.2 Notification requirements in §63.9.

64. 40 CFR Part 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or before November 7, 2006

The provisions in Subpart VV are not directly applicable to the equipment at this facility but portions are applicable as specified in 40 CFR Part 63 Subpart CC.

The definitions of “process unit” and “capital expenditure” in NSPS Subpart VV have been stayed (see 60.480(f) and 73 FR 31376, June 2, 2008). While the definition of “process unit” is stayed owners or operations shall use the definition of “process unit” provided in §60.480(f). In addition 60.482-1(g) was also stayed in the June, 2008 FR notice and has not been included.

The requirements below reflect the rule language in 40 CFR Part 60 Subpart VV as of the latest revisions to 40 CFR Part 60 Subpart VV published in the Federal Register on June 2, 2008. However, the permittee is subject to the latest version of 40 CFR Part 60 Subpart VV. The relevant requirements in 40 CFR Part 60 Subpart VV include, but are not limited to the following:

Standards: General (60.482-1)

64.1 Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482-1 through 60.482-10 or §60.480(e) for all equipment within 180 days of initial startup. (60.482-1(a))

64.2 Compliance with §§60.482-1 to 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485. (60.482-1(b))

64.3 An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in §60.484. (60.482-1(c)(1))

64.3.1 If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §60.482-2, §60.482-3, §60.482-5, §60.482-6, §60.482-7, §60.482-8, or §60.482-10, an owner or operator shall comply with the requirements of that determination. (60.482-1(c)(2))

64.4 Equipment that is in vacuum service is excluded from the requirements of §§60.482–2 to 60.482–10 if it is identified as required in §60.486(e)(5). (60.482-1(d))

64.5 Equipment that an owner or operator designates as being in VOC service less than 300 hours (hr)/yr is excluded from the requirements of §§60.482–2 through 60.482–10 if it is identified as required in §60.486(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section. (60.482-1(e))

64.6 If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps and valves at the frequency specified in the table in §60.482-1(f)(1) instead of monitoring as specified in §§60.482–2, 60.482–7, and 60.483–2. (60.482-1(f)(1))

64.6.1 Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered. (60.482-1(f)(2))

64.6.2 The monitoring frequencies specified in 60.482-1(f)(1) are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator 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 60.482-1(f)(3)(i) through (iv). (60.482-1(f)(3))

Standards: Pumps in light liquid service (60.482-2)

64.7 Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485(b), except as provided in §60.482–1(c) and (f) and 60.482-2(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 §60.482–1(c) and (f) and 60.482-2(d), (e), and (f). (60.482-2(a)(1))

64.8 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 §60.482–1(f). (60.482-2(a)(2))

64.9 If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. (60.482-2(b)(1))

64.10 If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either 60.482-2(b)(2)(i) or (ii). This requirement does not apply to a pump that was monitored after a previous weekly inspection if the instrument reading for that monitoring event was less than 10,000 ppm and the pump was not repaired since that monitoring event. (60.482-2(b)(2))

64.11 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 §60.482–9. (60.482-2(c)(1))

64.12 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 60.482-2(c)(2)(i) and (ii), where practicable. (60.482-2(c)(2))

64.13 Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in 60.482-2(d)(1) through (6) are met. (60.482-2(d))

64.14 Any pump that is designated, as described in §60.486(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 60.482-2(a), (c), and (d) if the pump (60.482-2(e)):

64.14.1 Has no externally actuated shaft penetrating the pump housing, (60.482-2(e)(1))

64.14.2 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 §60.485(c) (60.482-2(e)(2)), and

64.14.3 Is tested for compliance with 60.482-2(e)(2) initially upon designation, annually, and at other times requested by the Division. (60.482-2(e)(3))

64.15 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 §60.482–10, it is exempt from 60.482-2(a) through (e). (60.482-2(f))

64.16 Any pump that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of 60.482-2(a) and (d)(4) through (6) of this section if (60.482-2(g)):

64.16.1 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 60.482-2(a) (60.482-2(g)(1)); and

64.16.2 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 60.482-2(c) if a leak is detected. (60.482-2(g)(2))

64.17 Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of 60.482-2(a)(2) and (d)(4), and the daily requirements of 60.482-2(d)(5), provided that each pump is visually inspected as often as practicable and at least monthly. (60.482-2(e))

Standards: Compressors (60.482-3)

64.18 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 §60.482–1(c) and 60.482-3 (h), (i), and (j). (60.482-3(a))

64.19 Each compressor seal system as required in 60.482-3(a) shall be (60.482-3(b)):

64.19.1 Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure (60.482-3(b)(1)); or

64.19.2 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 §60.482–10 (60.482-3(b)(2)); or

64.19.3 Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. (60.482-3(b)(3))

64.20 The barrier fluid system shall be in heavy liquid service or shall not be in VOC service. (60.482-3(c))

64.21 Each barrier fluid system as described in 60.482-3(a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. (60.482-3(d))

64.22 Each sensor as required in 60.482-3(d) shall be checked daily or shall be equipped with an audible alarm. (60.482-3(e)(1))

64.23 The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both. (60.482-3(e)(2))

64.24 If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected. (60.482-3(f))

64.25 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 §60.482–9. (60.482-3(g)(1))

64.26 A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. (60.482-3(g)(2))

64.27 A compressor is exempt from the requirements of 60.482-3(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 §60.482–10, except as provided in 60.482-3(i). (60.482-3(h))

64.28 Any compressor that is designated, as described in §60.486(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 60.482-3(a)–(h) if the compressor (60.482-3(i)):

64.28.1 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 §60.485(c) (60.482-3(i)(1)); and

64.28.2 Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator. (60.482-3(i)(2))

64.29 Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from 60.482-3(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 60.482-3(a) through (e) and (h). (60.482-3(j))

Standards: Pressure relief devices in gas/vapor service (60.482-4)

64.30 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 §60.485(c). (60.482-4(a))

64.31 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 §60.482–9. (60.482-4(b)(1))

64.32 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 §60.485(c). (60.482-4(b)(2))

64.33 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 §60.482–10 is exempted from the requirements of 60.482-4(a) and (b). (60.482-4(c))

64.34 Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of 60.482-4(a) and (b), provided the owner or operator complies with the requirements in 60.482-4(d)(2). (60.482-4(d)(1))

64.35 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 §60.482–9. (60.482-4(d)(2))

Standards: Sampling connection systems (60-682-5)

64.36 Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482–1(c) and 60.482-5(c). (60.482-5(a))

64.37 Each closed-purge, closed-loop, or closed-vent system as required in 60.482-5(a) shall comply with the requirements specified in 60.482-5(b)(1) through (4). (60.482-5(b))

64.38 In situ sampling systems and sampling systems without purges are exempt from the requirements of 60.482-5(a) and (b). (60.482-5(c))

Standards: Open-ended valves or lines (60.482-6)

64.39 Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1(c) and 60.482-6(d) and (e). (60.482-6(a)(1))

64.40 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. (60.482-6(a)(2))

64.41 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. (60.482-6(b))

64.42 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 60.482-6(a) at all other times. (60.482-6(c))

64.43 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 60.482-6(a), (b) and (c). (60.482-6(d))

64.44 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 60.482-6(a) through (c) are exempt from the requirements of 60.482-6(a) through (c). (60.482-6(e))

Standards: Valves in gas/vapor service and in light liquid service (60.482-7)

64.45 Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485(b) and shall comply with 60.482-7(b) through (e), except as provided in 60.482-7(f), (g), and (h) of, §60.482–1(c) and (f), and §§60.483–1 and 60.483–2. (60.482-7(a)(1))

64.46 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 60.482-7(a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in 60.482-7(f), (g), and (h), §60.482–1(c), and §§60.483–1 and 60.483–2. (60.482-7(a)(2))

64.47 If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. (60.482-7(b))

64.48 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. (60.482-7(c)(1)(i))

64.49 As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into 2 or 3 subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup. (60.482-7(c)(1)(ii))

64.50 If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months. (60.482-7(c)(2))

64.51 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 §60.482–9. (60.482-7(d)(1))

64.52 A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. (60.482-7(d)(2))

64.53 First attempts at repair include, but are not limited to, the best practices specified in §60.482-7(e)(1) through (4) where practicable (60.482-7(e)):

64.54 Any valve that is designated, as described in §60.486(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 60.482-7 (a) if the valve (60.482-7(f)):

64.54.1 Has no external actuating mechanism in contact with the process fluid (60.482-7(f)(1)),

64.54.2 Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485(c) (60.482-7(f)(2)), and

64.54.3 Is tested for compliance with 60.482-7(f)(2) initially upon designation, annually, and at other times requested by the Division. (60.482-7(f)(3))

64.55 Any valve that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of 60.482-7(a) if (60.482-7(g)):

64.55.1 The owner or operator 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 60.482-7(a), (60.482-7(g)(1)) and

64.55.2 The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times. (60.482-7(g)(2))

64.56 Any valve that is designated, as described in §60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of 60.482-7(a) if (60.482-7(h)):

64.56.1 The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface. (60.482-7(h)(1))

64.56.2 The process unit within which the valve is located either becomes an affected facility through §60.14 or §60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor (60.482-7(h)(2)), and

64.56.3 The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year. (60.482-7(h)(3))

Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service and connectors (60.482-8)

64.57 If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures (60.482-8(a)):

64.57.1 The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485(b) and shall comply with the requirements of 60.482-8(b) through (d). (60.482-8(a)(1))

64.57.2 The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection. (60.482-8(a)(2))

64.58 If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. (60.482-8(b))

64.59 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 §60.482–9. (60.482-8(c)(1))

64.60 The first attempt at repair shall be made no later than 5 calendar days after each leak is detected. (60.482-8(c)(2))

64.61 First attempts at repair include, but are not limited to, the best practices described under §§60.482–2(c)(2) and 60.482–7(e). (60.482-8(d))

Standards: Delay of Repair (60.482-9)

64.62 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. (60.482-9(a))

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

64.64 Delay of repair for valves will be allowed if (60.482-9(c)):

64.64.1 The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair (60.482-9(c)(1)), and

64.64.2 When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482–10. (60.482-9(c)(1))

64.65 Delay of repair for pumps will be allowed if (60.482-9(d)):

64.65.1 Repair requires the use of a dual mechanical seal system that includes a barrier fluid system (60.482-9(d)(1)), and

64.65.2 Repair is completed as soon as practicable, but not later than 6 months after the leak was detected. (60.482-9(d)(2))

64.66 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. (60.482-9(e))

64.67 When delay of repair is allowed for a leaking pump or valve that remains in service, the pump or valve 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. (60.482-9(f))

Standards: Closed Vent systems and control devices (60.482-10)

64.68 Owners or operators of closed vent systems and control devices used to comply with provisions of 40 CFR Part 60 Subpart VV shall comply with the provisions of this section. (60.482-10(a))

64.69 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, whichever is less stringent. (60.482-10(b))

64.70 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 parts per million by volume, 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. (60.482-10(c))

64.71 Flares used to comply with 40 CFR Part 60 Subpart VV shall comply with the requirements of §60.18. (60.482-10(d))

64.72 Owners or operators of control devices used to comply with the provisions of 40 CFR Part 60 Subpart VV shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. (60.482-10(e))

64.73 Except as provided in 60.482-10(i) through (k), each closed vent system shall be inspected according to the procedures and schedule specified in 60.482-10(f)(1) and (f)(2). (60.482-10(f))

64.74 Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in 60.482-10(h). (60.482-10(g))

64.74.1 A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. (60.482-10(g)(1))

64.74.2 Repair shall be completed no later than 15 calendar days after the leak is detected. (60.482-10(g)(2))

64.75 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 owner or operator 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. (60.482-10(i))

64.76 If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of 60.482-10(f)(1)(i) and (f)(2). (60.482-10(i))

64.77 Any parts of the closed vent system that are designated, as described in 60.482-10(l)(1), as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in 60.482-10(j)(1) and (j)(2) (60.482-10(j)):

64.77.1 The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with 60.482-10(f)(1)(i) or (f)(2) (60.482-10(j)(1)); and

64.77.2 The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times. (60.482-10(j)(2))

64.78 Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of 60.482-10(f)(1)(i) and (f)(2) if they comply with the requirements specified in 60.482-10 (k)(1) through (k)(3). (60.482-10(k))

64.78.1 The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface (60.482-10(k)(1)); and

64.78.2 The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect (60.482-10(k)(2)); and

64.78.3 The owner or operator 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. (60.482-10(k)(3))

64.78.4 The owner or operator shall record the information specified in 60.482-10(l)(1) through (l)(5). (60.482-10(l))

64.79 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. (60.482-10(m))

Alternative standards for valves—allowable percentage of valves leaking (60.483-1)

64.80 An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent. (60.483-1(a))

64.81 The requirements in 60.483-1(b)(1) through (3) shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking. (60.483-1(b))

64.82 Performance tests shall be conducted in accordance with the requirements in 60.483-1(c)(1) through (3) (60.483-1(c))

64.83 Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485(h). (60.483-1(d))

Alternative standards for valves—skip period leak detection and repair (60.483-2)

64.84 An owner or operator may elect to comply with one of the alternative work practices specified in 60.483-2(b)(2) and (3). (60.483-2(a)(1))

64.85 An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d). (60.483-2(a)(2))

64.86 An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482-7. (60.483-2(b)(1))

64.87 After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. (60.483-2(b)(2))

64.88 After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. 90.483-2(b)(3))

64.89 If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482-7 but can again elect to use this section. (60.483-2(b)(4))

64.90 The percent of valves leaking shall be determined as described in §60.485(h). (60.483-2(b)(5))

64.91 An owner or operator must keep a record of the percent of valves found leaking during each leak detection period. (60.483-2(b)(6))

64.92 A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482-7(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve. (60.483-2(b)(7))

Test methods and procedures (60.485)

64.93 The test methods and procedures specified in §60.485 shall be followed.

Recordkeeping requirements (60.486)

64.94 Records shall be kept as required by §60.486.

Reporting requirements (60.487)

64.95 Semi-annual reports shall be submitted as required by §60.487.

65. 40 CFR Part 61 Subpart FF – National Emission Standards for Benzene Waste Operations

The refinery is subject to these requirements. According to the Consent Decree (H-01-4330) Suncor shall comply with the 6BQ option (61.342(e)).

The following equipment is subject to control requirements in 40 CFR Part FF: T60, T4501, T4502, T4503, T4504, T4507, T4508, T4514, T4515, T4516, T4517, T4518, Sumps (Lab, Spider, T58, T70, T75, T80, T775, T777), API Lift Station, T60 Lift Station, API Headworks, the Centrifuge, the pipeline receipt station sump, Tanks D-20, 17675 and 20529, Tank Truck Loading (LO-1), SU001 (Truck Loading Rack sump), controlled Truck Loading Rack Drains (F203) and the Truck Loading Rack Flare (R102) and associated piping from the Truck Loading Rack meter prover to the flare. The remaining waste streams, as applicable, will be included in assessing compliance with the 6 Mg/yr benzene quantity limit for uncontrolled waste streams.

The requirements below reflect the current rule language as of the latest revisions to 40 CFR Part 61 Subpart FF published in the Federal Register on December 4, 2003. However, if revisions to this Subpart are promulgated at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 61 Subpart FF. The relevant requirements in 40 CFR Part 63 Subpart FF include, but are not limited to the following:

Standards: General (61.342)

65.1 Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under §61.11, or by the initial startup for a new source with an initial startup after the effective date. (61.342(b)) According to the Consent Decree (H-01-4330) Suncor shall comply with the 6BQ option (61.342(e)).

65.2 As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows (61.342(e):

65.2.1 The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section (61.342(e)(1)); and

65.2.2 The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following (61.342(e)(2)):

65.2.2.1 The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in §61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in §61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section. (61.342(e)(2)(i)

65.2.2.2 The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with §61.355(k). (61.342(e)(2)(ii))

65.3 Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in §61.355 of this subpart. (61.342(g))

Standards: Tanks (61.343)

T4502, T4503, T4504, T4505, T4507, T4508, T4516, T4517, T4518, Lab Sump, Spider Sump (fixed portion), T58 Sump, T70 Sump, T75 Sump, T80 Sump, T775 Sump, T777 Sump, API Lift Station, T60 Lift Station, the pipeline receipt station sump, SU001 (Truck Loading Rack sump) and Tanks D-20, 17675 and 20529 are subject to these requirements.

65.4 Except as provided in paragraph (b) of this section and in §61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with §61.342(c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering. (61.343(a))

65.4.1 The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device. (61.343(a)(1))

65.4.1.1 The fixed roof shall meet the requirements in §61.343(a)(1)(i).

65.4.1.2 The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart. (61.343(a)(1)(ii)). **OR**

65.4.2 The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with the requirements specified in paragraph (e) of this section. (61.343(a)(2))

65.5 For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section. (61.343(b)) The pipeline receipt station sump and Tanks 17675 and 20529 meet the requirements in 61.343(b)(1) and are complying with the requirements in 61.343(b)(2).

65.5.1 The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the conditions in 61.343(b)(1).

65.5.2 The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i). (61.343(b)(2))

65.5.3 For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials. (61.343(b)(3))

65.6 Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly. (61.343(c))

65.7 Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification. (61.343(d))

65.8 Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section. (61.343(e))

Standards: Containers (61.345)

These requirements apply to the centrifuge, tank truck loading (LO-1) and various containers utilized at the refinery.

65.9 The owner or operator shall meet the following standards for each container in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart: (61.345(a))

65.9.1 The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the requirements in 61.345(a)(1)(i) and (ii). (61.345(a)(1))

65.9.2 When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section. (61.345(a)(2))

65.9.3 Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section. (61.345(a)(3))

65.9.4 If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the conditions in 61.345(a)(4)(i) through (iii) are met. (61.345(a)(4))

65.10 Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly. (61.345(b))

65.11 Except as provided in §61.350 of this subpart, 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 identification. (61.345(c))

Standards: Individual Drain Systems (61.346)

The API Headworks and the controlled Truck Loading Rack drains (F203) are subject to these requirements. When vapors from the API Headworks are routed to the RTO or carbon canisters, the alternative standards in Condition 65.13 are no longer applicable.

65.12 Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart (61.346(a)):

65.12.1 The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device. (61.346(a)(1))

65.12.1.1 The cover shall meet the requirements in 61.346(a)(1)(i)(A) through (C).

65.12.1.2 The closed-vent system and control device shall be designed and operated in accordance with §61.349 of this subpart. (61.346(a)(1)(ii))

65.12.2 Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly. (61.346(a)(2))

65.12.3 Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification. (61.346(a)(3))

65.13 As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements: (61.346(b))

65.13.1 Each drain shall be equipped with water seal controls or a tightly sealed cap or plug. (61.346(b)(1))

65.13.2 Each junction box shall be equipped with a cover and may have a 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. (61.346(b)(2))

65.13.2.1 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. (61.346(b)(2)(i))

65.13.2.2 One of the methods in §61.346(b)(2)(ii)(A) or (B) shall be used to control emissions from the junction box vent pipe to the atmosphere. (61.346(b)(2)(ii))

65.13.3 Each sewer line 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. (61.346(b)(3))

65.13.4 Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section (Conditions 65.13.1, 65.13.2 or 65.13.3) shall be inspected as follows: (61.346(b)(4))

65.13.4.1 Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls. (61.346(b)(4)(i))

65.13.4.2 Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed. (61.346(b)(4)(ii))

65.13.4.3 Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge. (61.346(b)(4)(iii))

65.13.4.4 The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions. (61.346(b)(4)(iv))

65.13.5 Except as provided in §61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification. (61.346(b)(5))

Standards: Oil-water Separators (61.347)

T4514 and T4515 are subject to these requirements.

65.14 Except as provided in §61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with §61.342(c)(1)(ii) of this subpart: (61.347(a))

65.14.1 The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device. (61.347(a)(1)) The fixed-roof shall meet the requirements in 61.347(a)(1)(i).

65.14.2 The closed-vent system and control device shall be designed and operated in accordance with the requirements of §61.349 of this subpart. (61.347(a)(1)(ii))

65.15 Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly. (61.347(b))

65.16 Except as provided in §61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification. (61.347(c))

Standards: Closed Vent Systems and Control Devices (61.349)

The Centrifuge Thermal Oxidizer, the Regenerative Thermal Oxidizer, the Truck Loading Rack Flare and piping from the meter prover to the Truck Loading Rack Flare and all Carbon Canisters are subject to these requirements.

65.17 For each closed-vent system and control device used to comply with standards in accordance with §§61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements: (61.349(a))

65.17.1 The closed vent system shall meet the requirements in 61.349(a)(1).

65.17.2 The control device shall be designed and operated in accordance with the requirements in 61.349(a)(2). For the control technologies addressed in this permit the following requirements apply:

65.17.2.1 An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the requirements in 61.349(a)(2)(i).

65.17.2.2 A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater. (61.349(a)(2)(ii))

65.17.2.3 A flare shall comply with the requirements of 40 CFR 60.18

(61.349(a)(2)(iii)).

65.18 Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device. (61.349(b))

65.19 An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods: (61.349(c))

65.19.1 Engineering calculations in accordance with requirements specified in §61.356(f) of this subpart; or

65.19.2 Performance tests conducted using the test methods (61.349(c)(1) and (2))

65.20 An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section (61.349(d))

65.21 The Division may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in §61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Division may specify alternative test methods and procedures, as appropriate. (61.349(e))

65.22 Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visible defects such as holes in ductwork or piping and loose connections. (61.349(f))

65.23 Except as provided in §61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed. (61.349(g))

65.24 The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with §61.354(c) of this subpart. (61.349(h))

Standards: Delay of Repair (61.350)

65.25 Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown. (61.350(a))

65.26 Repair of such equipment shall occur before the end of the next facility or unit shutdown. (61.350(b))

Alternative Standards for Tanks (61.351)

T60, T4501 and Spider Sump (floating portion) are subject to these requirements.

65.27 As an alternative to the standards for tanks specified in §61.343 of this subpart, an owner or operator may elect to comply with one of the methods specified in §61.351(a)(1) through (3). (61.351(a))

65.28 If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of §61.343 of this subpart applicable to the same facilities. (61.351(b))

Monitoring of Operations (61.354)

65.29 An owner or operator subject to the requirements in §61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in 61.354(c)(1) through (9), unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly. (61.354(c)) For the control technologies addressed in this permit the following requirements apply:

65.29.1 For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber. (61.354(c)(1))

65.29.2 For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder. (61.354(c)(3))

65.30 For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene 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 either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system. (61.354(d))

65.31 An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications. (61.354(e))

65.32 Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following: (61.354(f))

65.32.1 Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under §61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line. (61.354(f)(1))

65.32.2 Visually inspect the readings from each flow monitoring device required by §61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required. (61.354(f)(2))

65.33 Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure. (61.354(g))

Test Methods, Procedures and Compliance Provisions (61.355)

65.34 An owner or operator shall determine the total annual benzene quantity from facility waste using the procedures specified in §61.355(a).

65.35 For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section. (61.355(b))

65.36 For the purposes of the calculation required by §§61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section. (61.355(c))

65.37 An owner or operator shall test equipment for compliance with no detectable emissions as required in §§61.343 through 61.347, and §61.349 of this subpart in accordance with the requirements in §61.355(h).

65.38 An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under §61.349(a)(2) shall use the procedures in §61.355(i).

65.39 An owner or operator shall determine the benzene quantity for the purposes of the calculation required by §61.342(e)(2) using the procedures in §61.355(k).

Recordkeeping Requirements (61.356)

65.40 Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. 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. (61.356(a))

65.41 Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, 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 records specified in 61.355(b)(1) through (6). (61.356(b))

65.42 An owner or operator transferring waste off-site to another facility for treatment in accordance with §61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment. (61.356(c))

65.43 An owner or operator using control equipment in accordance with §§61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section. (61.356(d))

65.44 An owner or operator using a closed-vent system and control device in accordance with §61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device. (61.356(f))

65.44.1 A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur. (61.356(f)(1))

65.44.2 If engineering calculations are used to determine control device performance in accordance with §61.349(c), then a design analysis for the control device that includes for example (61.356(f)(2)):

65.44.2.1 Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters (61.356(f)(2)(i):

a. For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene 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. (61.356(f)(2)(i)(G))

65.44.3 If performance tests are used to determine control device performance in accordance with §61.349(c) of this subpart (61.356(f)(3)):

65.44.3.1 A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program. (61.356(f)(3)(i))

65.44.3.2 A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials. (61.356(f)(3)(ii))

65.44.3.3 A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials. (61.356(f)(3)(iii))

65.45 An owner or operator shall maintain a record for each visual inspection required by §§61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed. (61.356(g))

65.46 An owner or operator shall maintain a record for each test of no detectable emissions required by §§61.343 through 61.347 and §61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed. (61.356(h))

65.47 For each control device, the owner or operator shall maintain documentation that includes the applicable information specified in 61.356(j)(1) through (12) regarding the control device operation. (61.356(j)) For the control technologies addressed in this permit the following requirements apply:

65.47.1 Dates of startup and shutdown of the closed-vent system and control device. (61.356(j)(1))

65.47.2 A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device. (61.356(j)(2))

65.47.3 Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when (61.356(j)(3)):

65.47.3.1 Any valve car-seal or closure mechanism required under §61.349(a)(1)(ii) is broken or the by-pass line valve position has changed. (61.356(j)(3)(i))

65.47.3.2 Any valve car-seal or closure mechanism required under §61.349(a)(1)(ii) is broken or the by-pass line valve position has changed. (61.356(j)(3)(ii))

65.47.4 If a thermal vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. (61.356(j)(4))

65.47.5 If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent. (61.356(j)(4))

65.47.6 If a carbon adsorber that is not regenerated directly on site 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 then the existing carbon in the control device is replaced with fresh carbon. (61.356(j)(10))

65.48 An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b. (61.356(k))

65.49 If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure. (61.356(m))

Reporting Requirements (61.357)

65.50 If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Division the reports specified in §61.357(d).

65.51 An owner or operator who elects to install and operate the control equipment in §61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b. (61.357(e))

66. 40 CFR Part 63 Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants: Site Remediation

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63 Subpart GGGGG published in the Federal Register on July 10, 2020. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart GGGGG. The relevant requirements in 40 CFR Part 63 Subpart GGGGG include, but are not limited to the following:

Appendix I of the permit indicates those portions of the facility that are subject to these requirements and those that are not. Specifically, these requirements apply to the emission unit R102 (truck rack).

The remainder of the refinery is exempt from these provisions because site remediation is required by an order authorized under RCRA Section 7003 (40 CFR Part 63 §63.7881(b)(3)). In the event that site remediation at the remainder of the refinery is no longer subject to a RCRA order, the provisions in 40 CFR Part 63 Subpart GGGGG apply.

66.1 The permittee shall comply with the requirements in 40 CFR Part 63 Subpart GGGGG by one of the following methods:

66.1.1 Your site remediation activities are not subject to the requirements of this subpart, except for the recordkeeping requirements in this paragraph, provided that you meet the following requirements. (63.7881(c))

66.1.1.1 You determine that the total quantity of the HAP listed in Table 1 to this subpart that is contained in the remediation material excavated, extracted, pumped, or otherwise removed during all of the site remediation conducted at your facility is less than 1 megagram (Mg) annually. This exemption applies the 1 Mg limit on a facility-wide, annual basis, and there is no restriction to the number of site remediation that can be conducted during this period. (63.7881(c)(1))

66.1.1.2 You must prepare and maintain at your facility written documentation to support your determination that the total HAP quantity in your remediation materials for the year is less than 1 Mg. The documentation must include a description of your methodology and data used for determining the total HAP content of the remediation material. 63.7881(c)(2))

66.1.2 A site remediation that is completed within 30 consecutive calendar days according to the conditions in paragraphs (b)(1) through (3) of this section is not subject to the standards under paragraph (a) of this section. This exemption cannot be used for a site remediation involving the staged or intermittent cleanup of remediation material whereby the remediation activities at the site are started, stopped, and then re-started in a series of intervals, with durations less than 30-days per interval, when the time period from the beginning of the first interval to the end of the last interval exceeds 30 days. (63.7884(b))

66.1.2.1 The 30 consecutive calendar day period for a site remediation that qualifies for this exemption is determined according to actions taken by you as defined in paragraphs (b)(1)(i) through (iii) of this section. (63.7884(b)(1))

a. The first day of the 30-day period is defined as the day on which you initiate any action that removes, destroys, degrades, transforms, immobilizes, or otherwise manages the remediation materials. The following activities, when completed before beginning this initial action, are not counted as part of the 30-day period: Activities to characterize the type and extent of the contamination by collecting and analyzing samples; activities to obtain permits from Federal, State, or local authorities to conduct the site remediation; activities to schedule workers and necessary equipment; and activities to arrange for contractor or third party assistance in performing the site remediation. (63.7884(b)(1)(i))

b. The last day of the 30-day period is defined as the day on which treatment or disposal of all of the remediation materials generated by the cleanup is completed such that the organic constituents in these materials no longer have a reasonable potential for volatilizing and being released to the atmosphere. (63.7884(b)(1)(ii))

c. If treatment or disposal of the remediation materials is conducted at an off-site facility where the final treatment or disposal of the material cannot, or may not, be completed within the 30-day exemption period, then the shipment of all of the remediation material generated from your cleanup that is transferred to another party, or shipped to another facility, within the 30-day period, must be performed according to the applicable requirements specified in §63.7936. (63.7884(b)(1)(iii))

66.1.2.2 For the purpose of complying with paragraph (b)(1) of this section, if you ship or otherwise transfer the remediation material off-site you must include in the applicable shipping documentation, in addition to any notifications and certifications required under §63.7936, a statement that the shipped material was generated by a site remediation activity subject to the conditions of this exemption. The statement must include the date on which you initiated the site remediation activity generating the shipped remediation materials, as specified in paragraph (b)(1)(i) of this section, and the date 30 calendar days following your initiation date. (63.7884(b)(2))

66.1.2.3 You must prepare and maintain at your facility written documentation describing the exempted site remediation, and listing the initiation and completion dates for the site remediation. (63.7884(b)(3))

67. Sand Creek Remediation Project – Air Sparge/Soil Vapor Extraction (AS/SVE) and AS Systems

AIRS Pt 606 –Recovery Trench Zone F & G
AIRS Pt 615 – Suncor Western Property Boundary
AIRS Pt 616 Metro M & E East
AIRS Pt 617 – RPC Zone 2
AIRS Pt 618 – Metro Utility Corridor Zones 1 & 2
AIRS Pt 623 – Metro South Secondary Area Zone 1
AIRS Pt 624 – Metro South Secondary Area Zone 2
AIRS Pt 625 - Recovery Trench Zone E & H
AIRS Pt 634 – Metro Utility Corridor Zones 3 & 4
AIRS Pt 635 – PCA Subslab Depressurization
AIRS Pt 636 - NW Boundary Uncontrolled Zones 3 & 4
AIRS Pt 637 –Laboratory
AIRS Pt 638 – East Burlington Ditch
AIRS Pt 639 – West of Burlington Ditch

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	67.1	Pt 606 – 0.49 tons/year Pt 615 – 1.88 tons/year Pt 616 – 0.21 tons/year Pt 617 – 1.2 tons/year Pt 618 – 0.49 tons/year Pt 623 – 0.04 tons/year Pt 624 – 0.03 tons/year Pt 625 – 0.49 tons/year Pt 634 – 0.22 tons/year Pt 635 – 0.01 tons/year Pt 636 – 16.26 tons/year Pt 637 – 0.29 tons/year Pt 638 – 0.61 tons/year Pt 639 – 0.47 tons/year	See Condition 67.1	Recordkeeping and Calculation	Monthly
NO_X	67.2	TO-SUN-2 – 2.2 tons/year	0.50 lbs/hr	Recordkeeping and Calculation	Monthly
		CO-RPC-1 – 0.1 tons/year	2.2 x 10^{-2} lbs/hr		
CO		TO-SUN-2 – 5.2 tons/year	1.18 lbs/hr		
		CO-RPC-1 – 0.45 tons/year	0.10 lbs/hr		
Fuel Use – **TO-SUN-2 Only**	67.3	**TO-SUN-2** – 25.8 MMscf/year		Fuel Meter	Monthly
Hours of Operation	67.4			Recordkeeping	Monthly

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
AS/SVE Flow and AS Injection Monitoring	67.5			Flow Meter	Daily
Equipment and Control Device Requirements	67.6	See Condition 67.6		See Condition 67.6	
NSPS Requirements – **TO-SUN-2 Only**	67.7	40 CFR Part 60, Subpart Ja Fuel gas shall not contain H_2S in excess of: 162 ppmv, on a 3-hour rolling average, and 60 ppmv, on a 365-day rolling average		Fuel Gas Stream is Inherently Low in Sulfur	
		See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	
RACT	67.8	See Condition 67.8		See Condition 67.8	
Sampling for Contaminant Concentration	67.9	See Condition 67.9		See Condition 67.9	
Control Device Monitoring Requirements	67.10	Carbon Canisters - Breakthrough Thermal and Catalytic Oxidizers - Temperature		See Condition 67.10	
Opacity Requirements – **TO-SUN-2 and CO-RPC-1**	67.11	Not to exceed 20%, except as provided for below Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes		Fuel Restriction	Only Gaseous Fuel is Used
CAM Requirements	67.12	See Condition 67.12		See Condition 67.12	
SO_2 – **TO-SUN-2 Only**	67.13	0.3 lb SO_2/bbl/day of oil processed	See Condition 67.13	Recordkeeping and Calculation	Daily Monthly

67.1 VOC Emissions shall not exceed the limits listed in the above summary table. (Colorado Construction Permit 12AD1825, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X in accordance with the APENs submitted on November 12, 2015, red-lined December 3 & 4, 2015 (to revise the emissions limits for pts 606, 615, 616, 617, 618 and 625, add limitations for pts 634, 635 and 636, and to remove monthly limits for pt 625) and February 25, 2022 (to revise emission limits for pts 606, 618 and 625). For pt 637, as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include VOC limit as requested on the APEN submitted on September 7, 2016, redlined October 3, 2016. For pt 638, as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include VOC limit as requested on the APEN submitted

May 30, 2019, red-lined July 16, 2019. For pt 639, as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include VOC limit as requested on the APEN submitted March 31, 2020) Compliance with the VOC emissions limitations shall be monitored by calculating monthly emissions as follows:

67.1.1 **For all but Pts 615 and 617**, monthly VOC emissions shall be calculated using the most recent or average (if more than one sample during the month) contaminant concentration (as required by Condition 67.9**)**, AS/SVE flow rate (as required by Condition 67.5) and monthly hours of operation (as required by Condition 67.4) in the following equation:

$$VOC_{uncont}\text{ (tons/month)} = \frac{\text{C x MW x Q x 60 x monthly hours of operation}}{\text{1,000,000 x 385.3 x 2,000}}$$

A control efficiency may be applied for AS/SVE systems equipped with carbon canisters provided that the carbon canisters are operated and maintained in accordance with the requirements in Conditions 67.6.1 and 67.10.1

$$VOC_{cont}\text{ (tons/month)} = VOC_{uncont} \text{ x } (100 – CE)/100$$

Where: C = measured contaminant concentration, ppmv
Q = AS/SVE flow rate (scfm)
MW = molecular weight of contaminant, in lb/lbmole (assumed to be 69 lb/lbmole)
CE = control efficiency, 98% for two carbon canisters in series

67.1.2 **For Pt 615 and Pt 617**, monthly VOC emissions shall be calculated by multiplying the emissions factors in the table below by hours of operation (as required by Condition 67.4) in the equation below:

VOC (tons/month) = EF (lbs/hr) x hours of operation (hours per month)/2000 lbs/ton

Emission Unit	Emission Factor (lb/hr)	Source of Emission Factor
TO-SUN-2	2.27×10^{-2}	From performance tests conducted on February 24 and 25, 2015
CO-RPC-1	2.94×10^{-3}	

67.1.3 **For Pt 636 (uncontrolled, AS only systems)**, monthly VOC emissions shall be calculated using the most recent or average (if more than one sample during the month) contaminant concentration (as required by Condition 67.9) and the monthly volume of air injected into the system (as required by Condition 67.5) in the following equation:

$$\text{VOC (tons/month)} = \frac{\text{C x MW x monthly volume of air injected (scf/month)}}{\text{1,000,000 x 385.3 x 2,000}}$$

Where: C = measured contaminant concentration, ppmv
Q = air injection flow rate, scf/month
MW = weight of contaminant, in lb/lbmole (assumed to be 69 lb/lbmole)

67.1.4 The VOC emissions limitations for the points listed shall be met regardless of the control device used and the control efficiency of the control device used. The appropriate control efficiency shall be applied to the above stipulated monthly emissions calculation methodologies for the amount of time that the control device was used for the month. (Colorado Construction Permit 12AD1825) If the controls currently installed on **Pts 615 and pt 617** are replaced with either no control or carbon canisters, emissions for these systems shall be estimated in accordance with the requirements in Condition 67.1.1.

Monthly emissions shall be calculated by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

67.2 NO_X and CO emissions **from TO-SUN-2 and CO-RPC-1** shall not exceed the limits listed in the above table. (Colorado Construction Permit 12AD1825, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X to include CO and NO_X limits for CO-RPC-1 and to revise CO emissions for TO-SUN-2). Monthly emissions of NO_X and CO from TO-SUN-2 and CO-RPC-1 shall be calculated by multiplying the emissions factors in the table below by hours of operation (as required by Condition 67.4) in the equation below:

CO or NO_X emissions (tons/month) = EF (lbs/hr) x monthly hours of operation /2000 lbs/ton

Emission Unit	Emission Factor (lb/hr)		Source of Emission Factor
	NO_X	CO	
TO-SUN-2	0.50	1.18	For TO-SUN-2, both NO_X and CO: The sum of the AP-42 emission factors from Section 1.4 (dated 7/1998), Table 1.4-1 for small boilers, converted to lb/MMBtu based on a heat content of 1020 Btu/scf (per footnote 1) and Section 13.5 (dated 4/2015), Tables 13.5-1 & 2. For CO-RPC-1, both NO_X and CO: AP-42, Section 13.5 (dated 4/15), Tables 13.5-1 & 2. The lb/MMBtu emission factors were multiplied by the design heat input rate (3 MMBtu/hr for TO-SUN-2 and 0.33 MMBtu/hr for CO-RPC-1) to get the lb/hr factors.
CO-RPC-1	2.2×10^{-2}	0.10	

Monthly emissions shall be calculated by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

67.3 Natural gas consumption from **TO-SUN-2** shall not exceed the limitation in the above table. (Colorado Construction Permit 12AD1825). Compliance with the natural gas consumption limit shall be monitored by recording the natural gas consumption from TO-SUN-2 monthly. Monthly natural gas consumption shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

Daily natural gas consumption shall be determined by dividing monthly natural gas consumption by the number of days TO-SUN-2 was operated as required by Condition 67.4.

67.4 Hours of operation of the **AS/SVE systems, TO-SUN-2 and CO-RPC-1** shall be determined by recording the number of days the AS/SVE system, TO-SUN-2 and CO-RPC-1 is operated. The number of days the AS/SVE system, TO-SUN-2 and CO-RPC-1 are operated during the month shall be multiplied by 24 to determine the monthly hours of operation. Days of operation recorded shall reflect the number of days the AS/SVE systems operated under a specific control device or without a control device, in the event that the control device is changed and/or removed during the month. Monthly hours of operation shall be used to calculate emissions as specified in Conditions 67.1 and 67.2.

67.5 The flow rate for each **AS/SVE System** and the injection rate for **Pt 636 (AS (uncontrolled) systems)** shall be monitored and recorded during each business day that the AS/SVE or AS system is operated. Daily records of the AS/SVE and AS flow and injection rates shall be used as follows:

67.5.1 The daily records of the AS/SVE flow rates shall maintained and made available to the Division to ensure that the daily AS/SVE capacity does not exceed the capacity of the control device used for the system. As of revised permit issuance [February 1, 2016], the AS/SVE capacity and control device capacity for each unit is listed in the table in Condition 67.6.2.

67.5.2 The daily AS/SVE system flow rates recorded during a calendar month shall be averaged together and used to calculate monthly emissions as specified in Condition 67.1.1.

67.5.3 The daily AS system injection rates shall be summed to determine the amount of air injected during the month. The monthly quantity of air injected in the AS system shall be used to calculate monthly emissions as specified in Condition 67.1.3.

67.6 The AS/SVE systems, AS (uncontrolled) systems and various control devices are subject to the following requirements:

67.6.1 The AS/SVE and AS systems, shall be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the AS/SVE and AS systems and control devices and good engineering practices, such as records of routine maintenance shall be maintained and made available to the Division upon request.

67.6.2 As of revised permit issuance **July 9, 2024**, the control devices used on the AS/SVE Systems are shown in the table below. The control devices listed in the table below may be rearranged as needed as long as the emissions from each AS/SVE System (AIRS pt) meet the emissions limits specified in Condition 67.1, except as noted in Condition 67.6.3. (Colorado Construction Permit 12AD1825, as modified under the provisions of Section I, Condition 1.3 to exclude movement of TO-SUN-2 and CO-RPC-1).

The remediation systems addressed in this Condition 67 may be operated without the use of control equipment once uncontrolled VOC emissions from the system drop below the system's VOC emissions limit. (Colorado Construction Permit 12AD1825)

The permittee shall keep a log that shows which control device was used at all times to control emissions for each point, and the dates and hours that the control devices were operated at each point. (Colorado Construction Permit 12AD1825).

Additional carbon canister systems that are not listed in the table below may be used as control devices provided that the carbon canister systems consist of two canisters in series, rated at 500 scfm per set.

AIRS point (pt)	AS/SVE System		Control Device		
	Description	Capacity	Description	Capacity	Efficiency
606	One Blower	750 scfm	CC-MET-8, -8a, & -8b Three sets of two carbon canisters (ccs) in series	1,500 scfm (500 per set)	98%
615	Two Blowers	2,000 scfm (1,000 each)	TO-SUN-2	10,000 scfm	N/A*
616	**Two Blowers**	**2,400 scfm (1,200 each)**	**CC-MET-9, -9a & -9b Three sets of two ccs in series**	**1,500 scfm (500 per set)**	**98%**
617	**Two Blowers****	**1,500 scfm (750 each)**	**CO-RPC-1**	**750 scfm**	**N/A***
618	**Two Blowers****	**1,500 scfm (750 each)**	**CC-MET-7a & -7b Two sets of two (2) ccs in series**	**1,000 scfm (500 per set)**	**98%**
623	One Blower**	750 scfm	CC-MET-6a, -6b & -6c Three sets of two (2) ccs in series	1,500 scfm (500 per set)	98%
624	One Blower**	750 scfm	CC-MET-6a, -6b & -6c Three sets of two (2) ccs in series	1,500 scfm (500 per set)	98%
625	One Blower	750 scfm	CC-MET-8, -8a & -8b Three sets of two (2) ccs in series	1,500 scfm (500 per set)	98%
634	**Four Blowers**	**3,350 scfm (3 at 850 each, 1 at 800)**	**CC-MET-7c, -7d, -7e & -7f Four sets of two (2) ccs in series**	**2,000 scfm (500 per set)**	**98%**
635	One Blower	500 scfm	CC-SUN-3 Two (2) ccs in series	500 scfm	98%
637	One Blower	107 scfm	CC-SUN-2 Two (2) ccs in series	500 scfm	98%
638	Two Blowers	1,300 scfm (650 each)	CC-MET-5c, -5a, -5b & -5d Four sets of two (2) ccs in series	2,000 scfm (500 per set)	98%
639	Two Blowers	1,000 scfm (500 each)	CC-MET-10a (north) and-10b (south)	1,000 scfm (500 per set)	98%

Entries in bold have AS/SVE systems with design flow rates greater than the control device flow rate.

*Control efficiency was not verified by performance test, so it is not listed.
**Booster blower is located between SVE blowers and control device.

67.6.3 **TO-SUN-2 and CO-RPC-1** may not be relocated without first revising the Title V permit or obtaining a construction permit.

67.6.4 The AS/SVE systems (e.g. blowers) addressed in this permit may be replaced with a system with a blower capacity less than or equal to the capacity of the blower for the existing system. The permittee shall maintain a log indicating the date that AS/SVE system is replaced and the identifying information for the replacement system (e.g. make, model, serial no. and design flow rate). A revised Air Pollutant Emissions Notice (APEN) that includes the specific manufacturer, model and serial number and capacity (scfm) of the permanent replacement blower shall be filed with the Division for the permanent blower within 14 calendar days of commencing operation of the replacement blower.

67.6.5 New wells may be tied into any existing AS/SVE or AS only systems provided the emissions limitations for the systems are met and that contaminant sampling is conducted in accordance with the requirements in Condition 67.9.2.

67.6.6 No new AS/SVE System or AS System may be installed and operated without first revising the Title V permit or obtaining a construction permit.

67.7 **TO-SUN-2** is subject to NSPS requirements as follows:

67.7.1 **TO-SUN-2** is subject to the NSPS general provisions in 40 CFR Part 60, Subpart A as set forth in Condition 56 of this permit.

67.7.2 **TO-SUN-2** is a fuel gas combustion device and is subject to the requirements in 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007 as set forth in Condition 46 of this permit.

Note that TO-SUN-2 is exempt from the H_2S monitoring requirements as specified in Condition 46.15 because TO-SUN-2 combusts fuel gas that is inherently low in sulfur.

67.8 The AS/SVE and AS Systems are subject to RACT requirements for VOC. (Colorado Construction Permit 12AD1825 and Colorado Regulation No. 3, Part C, Section III.D.2.a). RACT has been determined as follows:

67.8.1 RACT for all of the AS/SVE Systems **except for pt 636** has been determined to be the control technology employed (see Condition 67.6.2) and the emissions limitations in Condition 67.1. As provided for in Condition 67.6.2, the control technology may be removed provided the VOC emissions limitations may be met and in those cases RACT has been determined to be the emissions limitations in Condition 67.1.

67.8.2 RACT for the AS Systems associated with **Pt 636** has been determined to be the emissions limitations in Condition 67.1. Soil vapor extraction and an associated control technology is not feasible for these zones since the groundwater table is shallow in these locations.

67.9 Sampling for contaminant concentrations shall be conducted as follows:

67.9.1 For **each AS/SVE and AS system except for Pt 615 and Pt 636 Zone 4**, samples of contaminant concentrations shall be taken at a frequency of once a week for the first month of operation, once a month for the next month and then once every three months thereafter. The samples shall be analyzed using the appropriate EPA methods for Total Volatile Petroleum Hydrocarbons (TVPH). For AS/SVE systems, the sample shall be taken at the outlet of the AS/SVE blower prior to the control device and any booster blower, if applicable. For Pt 636, Zone 3 (AS system, uncontrolled), samples shall be taken at various sample points below ground, prior to being emitted. (Colorado Construction Permit 12AD1825, as modified under the provisions of Section I, Condition 1.3 to correct sample location for systems equipped with carbon canisters and to address pt 636 Zone 3 which is not equipped with SVE and is uncontrolled)

67.9.2 For **Pt 636 Zone 4 (AS system, uncontrolled), Pt 615 and for when new wells are tied into any existing AS/SVE or AS system**, samples of contaminant concentrations shall be taken at a frequency of once a week for the first three months of operation, once a month for the fourth month and then once every three months thereafter. The samples shall be analyzed using the appropriate EPA methods for Total Volatile Petroleum Hydrocarbons (TVPH). For AS/SVE systems, the sample shall be taken at the outlet of the AS/SVE blower prior to the control device and any booster blower, if applicable. For Pt 636, Zone 4 (uncontrolled, no SVE system) or any other AS system, samples shall be taken at sample points below ground, prior to being emitted.

67.10 Monitoring of the control devices shall be conducted as follows:

67.10.1 <u>Two carbon canisters in series.</u> The permittee shall monitor for breakthrough between the primary and secondary carbon canisters at times there is actual flow to the carbon canisters on the frequency specified in Conditions 67.10.1.1 through 67.10.1.4. Breakthrough monitoring shall be conducted on each set of two carbon canisters in series (e.g. CC-MET-6a) controlling a given AS/SVE System. Breakthrough is defined in Condition 67.10.1.6.

67.10.1.1 During the first three months of operation following issuance of construction permit 12AD1825 (issued September 26, 2014), frequency of breakthrough monitoring shall be daily.

67.10.1.2 If breakthrough is detected less than once per month in any three consecutive months of daily breakthrough monitoring, frequency of monitoring shall be reduced to weekly:

67.10.1.3 If breakthrough is not detected during any three consecutive months of weekly breakthrough monitoring, frequency of breakthrough monitoring shall be reduced to monthly.

67.10.1.4 At any time breakthrough is experienced in two consecutive scheduled monitoring events for a set of two carbon canisters in series, frequency will revert back to the previous monitoring frequency.

67.10.1.5 Except as provided for below, breakthrough from carbon canisters shall be defined as a concentration equal to or greater than 5 ppm VOC:

a. If a concentration of 5 ppm or greater VOC is detected between the first and second carbon canisters, the permittee may monitor the VOC concentration at the inlet of the carbon canisters and between the primary and second primary canister. Breakthrough under this scenario is defined as a VOC reduction less than 95%.

b. The inlet monitoring specified in Condition 67.10.1.5.a shall be conducted at the outlet of the AS/SVE blower prior to the control device and any booster blower, if applicable.

c. Records of the inlet and outlet VOC concentrations and the percent VOC reduction shall be maintained and made available to the Division upon request.

67.10.1.6 Within 24 hours after breakthrough is detected:

a. The carbon canisters will be replaced, or

b. The AS/SVE system shall be shutdown.

c. If the AS/SVE system is shutdown, then the carbon canisters shall be replaced prior to startup of the AS/SVE system.

67.10.2 <u>TO-SUN-2.</u> For purposes of assuring compliance with the annual VOC emissions limits in Condition 67.1, TO-SUN-2 shall be operated such that the temperature in the combustion chamber is not less than 1,588 °F. The temperature shall be monitored in accordance with the CAM Plan in Appendix M and the CAM requirements in Condition 60 (as required by Condition 67.12).

67.10.3 <u>CO-RPC-1.</u> For purposes of assuring compliance with the annual VOC emissions limits in Condition 67.1, CO-RPC-1 shall be operated such that the catalyst inlet temperature is not less than 775 °F. The temperature shall be monitored in accordance with the CAM Plan in Appendix M and the CAM requirements in Condition 60 (as required by Condition 67.12).

67.11 **TO-SUN-2 and CO-RPC-1** are subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. In the absence of credible evidence to the contrary, compliance with the opacity limits is presumed provided only vapors from SVE systems and/or natural gas are combusted and/or oxidized in these units. Records shall be maintained to verify that only vapors from SVE systems and/or natural gas have been combusted and/or oxidized in these units.

67.12 AIRS pts 615 and 617 are subject to the compliance assurance monitoring (CAM) requirements with respect to the VOC limitations identified in Condition 67.1, except as provided for in Conditions 67.12.1 and 67.12.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM Plans in Appendix M.

67.12.1 The CAM requirements do not apply to AIRs pt 615 until the area in which the source is located is reclassified as a severe ozone non-attainment area.

67.12.2 As provided for under the provisions of Condition 67.6.2, if either AIRS pt 615 or 617 can be operated in compliance with the emission limits in Condition 67.1 without the use of a control device, the CAM requirements will no longer apply to that equipment.

67.13 Sulfur dioxide emissions from **TO-SUN-2** shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit. For purposes of assessing compliance with the Regulation No. 1 emissions limit, daily SO_2 emissions shall be calculated as follows:

SO_2 emissions from TO-SUN-2 (lb/day) = SO_2 from waste gas (lb/day) + SO_2 from natural gas consumption (lb/day)

SO_2 (lb/day) = 4.0×10^{-3} lb/hr x hours of Pt 615 AS/SVE operation (hours/day)

SO_2 (lb/day) = 0.6 lb/MMscf x daily natural gas consumption (MMscf/day)

Where: 0.6 lb/MMscf = SO_2 emission factor from AP-42, Section 1.4 (dated 7/98), Table 1.4-2
Hours of operation for Pt 615 AS/SVE as required by Condition 67.4
Natural gas consumption (MMscf/day) as required by Condition 67.3
4.0×10^{-3} lb/hr SO_2 = calculated from the below equation.

4.0×10^{-3} lb/hr SO_2 = 0.2 scf $H_2S/10^6$ scf x lb-mole H_2S/385.3 scf H_2S x lb-mole SO_2/lb-mole H_2S x 64 lbs SO_2/lb-mole SO_2 x 2,000 scf/min x 60 min/hr

Where: 0.2 ppmv H_2S (scf/10^6 scf) = detection level during 14-day testing period
385.3 = molar volume (scf/lb-mole)
2,000 scf/min = total blower flowrate for Pt 615 AS/SVE, 1,000 scf/min per blower

68. Sand Creek Remediation Project – Tanks and Tank Truck Loading

LO-1 (AIRS pt 628) – Tank Truck Loading, D-20 (AIRS pt 631) – Storage Tanks (21,150 gal) and Tanks 17675 & 20529 (APEN exempt) – Two (2) Storage Tanks (525 gal, each)

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC Emissions	68.1	Tank D-20: 0.1 tons/year	TANKS	Recordkeeping and Calculation	Monthly
		Tank Truck Loading (LO-1) 1.5 tons/year	See Condition 68.1.2		

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
RACT	68.2 68.3	See Conditions 68.2 and 68.3		See Conditions 68.2 and 68.3	
NSPS	68.4	General Provisions – Subpart A (Condition 56) Specific Requirements – Subpart Kb (Condition 48)		See 40 CFR Part 60 Subparts A (Condition 56) and Kb (Condition 53)	
MACT	68.5	See 40 CFR Part 63 Subpart CC (Condition 53)		See 40 CFR Part 63 Subpart CC (Condition 53)	
Tank D-20 Control Device Requirements	68.6	Two (2) Carbon Canisters in Series		Breakthrough Monitoring	Daily or No Less Than Once Every 14 Days
BWON	68.7	See 40 CFR Part 61 Subpart FF (Condition 65)		See 40 CFR Part 61 Subpart FF (Condition 65)	
Throughput Limitations	68.8	Tank D-20 534,767 gallons/year Tank Truck Loading (LO-1) 766,500 gallons/year		Recordkeeping	Monthly

Note that the two (2) 525 gallon tanks (Tanks 17675 & 20529) are exempt from the APEN reporting requirements in Regulation No. 3, Part A and the construction permit requirements in Regulation No. 3, Part B provided actual, uncontrolled emissions are below the APEN de minimis levels.

68.1 VOC Emissions **from Tank D-20 and tank truck loading (LO-1)** shall not exceed the limits listed in the above summary table (Colorado Construction Permit 12AD1826, as modified under the provisions of Section I, Condition 1.3 to remove the monthly limits for D-20). Compliance with the annual limits shall be monitored as follows:

68.1.1 For **Tank D-20**, compliance with the annual VOC emissions limit shall be monitored by calculating monthly emissions using EPA's TANKS 4.09d program and the monthly throughput (as required by Condition 68.8). Emissions shall be based on the average (or numerically greater) RVP of the material stored over the monthly period. A control efficiency of 98% may be applied to the monthly emissions determined from the TANKS run provided the closed vent system and carbon canisters are operated and maintained in accordance with the requirements in Conditions 68.6 and 68.7.

68.1.2 For **tank truck loading (LO-1)**, compliance with the annual VOC emissions limit shall be monitored by calculating emissions monthly using the monthly quantity of materials loaded (as required by Condition 68.8) in the equation below:

VOC (tons/mo) = [quantity of materials loaded (10^3 gal/mo) x L_L (lbs/10^3 gal)]/2000 (lb/ton)

L_L = 12.46 x SPM/T

Where: LL = loading, loss (lb/10^3 gal), from AP-42, Section 5.2 (dated 6/08), equation 1
S = saturation factor (per Table 5.2-1 of AP-42)
P = true vapor pressure of liquid loaded, psia

M = molecular weight of vapors (lb/lbmole)
T = temperature of bulk liquid loaded (º R)

Monthly emissions shall be based on the average vapor heat content, vapor pressure, temperature and molecular weight (of vapors) of the liquids loaded over the monthly period.

Monthly emissions **from Tank D-20 and tank truck loading (LO-1)** shall be calculated by the end of the subsequent month and used in twelve month rolling totals to monitor compliance with the annual emissions limitation. Each month new twelve month totals shall be calculated using the previous twelve months data.

68.2 The tanks are subject to the RACT requirements in Colorado Regulation No. 24, as follows:

68.2.1 **Tanks D-20, 17675 and 20529** are subject to Colorado Regulation No. 7, Part B, Section I.A, as set forth in Condition 39.1 of this permit.

68.2.2 **Tank D-20** is subject to Colorado Regulation No. 24, Part B, Section IV.B.3 as set forth in Condition 41.6 of this permit.

68.3 **Tank D-20 and tank truck loading (LO-1)** are subject to RACT requirements for VOC (Colorado Construction Permit 12AD1826 and Colorado Regulation No. 3, Part C, Section III.D.2.a). RACT has been determined as follows:

68.3.1 For Tank D-20, RACT has been determined to be the requirements in Condition 68.2.

68.3.2 For tank truck loading (LO-1), RACT has been determined to be the requirements for loading containers in Condition 68.7.

68.4 **Tank D-20** is subject to NSPS requirements as follows:

68.4.1 This tank is subject to the NSPS general provisions in 40 CFR Part 60, Subpart A as set forth in Condition 56 of this permit.

68.4.2 This tank is subject to the specific NSPS requirements for volatile organic liquid (including petroleum liquids) storage vessels in 40 CFR Part 60, Subpart Kb, as set forth in Condition 48 of this permit.

68.5 **Tank D-20** is subject to the requirements of 40 CFR Part 63, Subpart CC, as set forth in Condition 53 of this permit.

68.6 **Tank D-20** shall be vented through a closed vent system to two (2) carbon canisters in series. (Colorado Construction Permit 12AD1826) The carbon canisters shall be monitored for breakthrough as follows:

68.6.1 The source shall monitor for breakthrough between the primary and secondary carbon canisters at times there is actual flow to the carbon canisters daily or at intervals no greater than once every 14 days.

68.6.2 Breakthrough from carbon canisters shall be defined as a concentration equal to or greater than 5 ppm VOC.

68.6.3 The carbon canisters will be replaced within 24 hours after breakthrough is detected.

Records shall be maintained of the dates when breakthrough monitoring is conducted, breakthrough is detected and carbon canisters are replaced.

68.7 **Tanks D-20, 17675 and 20529 and tank truck loading (LO-1)** are subject to the requirements of 40 CFR Part 61, Subpart FF, as set forth in Condition 65 of this permit.

68.8 Throughput **through Tank D-20 and tank truck loading (LO-1)** shall not exceed the limits listed in the above summary table (Colorado Construction Permit 12AD1826, as modified under the provisions of Section I, Condition 1.3 to remove the monthly limits for D-20). Compliance with the annual limits shall be monitored by recording the quantity of material processed through tank D-20 and loaded into tank trucks monthly. Monthly quantities of material processed through tank D-20 and loaded into tank trucks shall be used in twelve month rolling totals to monitor compliance with the annual limitations. Each month new twelve month totals shall be calculated using the previous twelve months data.

69. Sand Creek Remediation Project – Project Wide Requirements

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Insignificant Activity Tracking - NO_X and VOC	69.1	VOC 15.6 tons/year NO_X 21.5 tons/year		Recordkeeping and Calculation	Annually
Restrictions on Relaxing Emissions Limitations	69.2	See Condition 69.2		See Condition 69.2	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

69.1 The uncontrolled potential to emit from all insignificant activities associated the Sand Creek Remediation Project shall not exceed the limitations listed in the above table. (Colorado Construction Permits 12AD1825 and 12AD1826, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulations No. 3 Part B, Section II.A.6 and Part C, Section X to adjust the levels to revise the NO_X and VOC emissions limitations to reflect NO_X emissions from all fuel burning equipment noted in 12AD1825 and the APEN required fuel burning equipment note in the 9/26/14 exemption letter (12AD1827) and to reflect current VOC permitted emissions)

For the purposes of this Condition 69.1, the Sand Creek Remediation Project shall be defined as any remediation activity or equipment that is in any way associated with the reformate release from an underground dead leg line connected to line number 6"-HN-08-0846-N-A2-1, Circuit Number 404-002-3, that was reported to the Department on February 25, 2011.

Insignificant activities from the Sand Creek Remediation Project that are sources of VOC or NO_X emissions shall be tracked and potential emissions (uncontrolled emissions at maximum capacity for 8760 hours per year) from these shall be estimated annually (calendar year basis) to ensure that emissions are below the specified limits. Any insignificant activity that is in place for part of the calendar shall be counted as being on site for the full calendar year. For purposes of this analysis, an insignificant activity is identified as any piece of equipment that emits NO_X or VOC emissions below the APEN de minimis level (actual, uncontrolled emissions below 1 ton/year) and that is not subject to emission limitations in Sections II.67 and 68 of this permit.

69.2 The requirements of Colorado Regulation No. 3, Part D shall apply to the Sand Creek Remediation Project Equipment at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Construction Permits 12AD1825 and 12AD1826, as modified under the provisions of Section I, Condition 1.3 and Colorado Regulations No. 3 Part B, Section II.A.6 and Part C, Section X to revise the permitted VOC emissions level).

With respect to this Condition 69.2, Colorado Regulation No. 3, Part D requirements may apply to future modifications if the emission limitations are modified to equal or exceed the following thresholds:

AIRS Point No.*	Equipment Description	Pollutant	Program	Emissions (tons/yr)	
				Threshold	Current Permit Limit
606, 615 – 618, 623 – 625, 628, 631, 634 – 638 & 639	AS/SVE Systems, Product Storage Tanks and Tank Truck Loading.	VOC	NANSR	40	24.3

*Only the VOC permitted sources are noted here. If emissions from the Sand Creek Remediation Project were relaxed to exceed 40 tons/yr of VOC, NANSR would apply to all emissions units associated with the Sand Creek Remediation Project that emit VOC. This would include any that currently qualify as insignificant activities as noted in Condition 69.1.

70. Tank Cleaning and Degassing –P1DGTO

Thermal Oxidizer for Degassing and Cleaning Tanks

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
VOC	70.1	17.2 tons/year **(Refinery-Wide)**	See Condition 70.1	Recordkeeping and Calculation	Per Tank Monthly
NO_X		2.73 tons/year **(Refinery-Wide)**	0.14 lb/MMBtu	Recordkeeping and Calculations	Per Tank Monthly
CO		1.57 tons/year **(Refinery-Wide)**	0.082 lb/MMBtu		
PM			7.65×10^{-3} lb/MMBtu		
PM_{10}					
SO_2			See Condition 70.1.3.2		Daily, Monthly
	70.2	0.3 lb SO_2/bbl/day of oil processed	See Condition 70.2		
Thermal Oxidizer (TO) Requirements	70.3	Design Rate Not to Exceed 20 Million Btu per hour		See Condition 70.3	
		Maintain TO Temperature at or Above 1400 ºF			
RACT	70.4			See Condition 70.4	
Propane/LPG Consumption	70.5	38,400,000,000 Btu/year **(Refinery-Wide)**		Fuel Meter Recordkeeping	Daily, Monthly
NSPS Requirements	70.6	40 CFR Part 60, Subpart J[1] Fuel gas shall not contain H_2S in excess of excess of 0.10 gr/scf, on a 3-hour rolling average[1]		H_2S Sampling	See Condition 70.6
		40 CFR Part 60, Subpart Ja Fuel gas shall not contain H_2S in excess of: 162 ppmv, on a 3-hour rolling average, and 60 ppmv, on a 365-day rolling average			
		See 40 CFR Part 60 Subpart A (Condition 56)		See 40 CFR Part 60 Subpart A (Condition 56)	

Parameter	Permit Condition Number	Limitation	Emission Factor	Monitoring	
				Method	Interval
Opacity Requirements	70.7	Not to exceed 20%, except as provided for below		Fuel Restriction	Only Gaseous Fuel is Used
		Not to exceed 30%, for a period or periods aggregating more than six (6) minutes in any 60 consecutive minutes			
Restrictions on Relaxing Emission Limitations	70.8			Recordkeeping and Calculation	Per Tank
CAM Requirements	70.9	These requirements apply beginning on the date the area is reclassified as a severe ozone nonattainment area. See Condition 70.9		See Condition 70.9	

[1]The preamble to the final rule for NSPS Subpart Ja indicates that the NSPS J limit is equivalent to 162 ppmv H_2S averaged over a 3-hour period (See 73 FR 35852).

70.1 Emissions of air pollutants are subject to the following requirements:

70.1.1 VOC emissions from tank cleaning and/or degassing shall not exceed 17.2 tons year. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 based on requested emissions indicated on the APEN submitted on February 25, 2022.) **This limit includes emissions from cleaning and/or degassing of tanks located throughout the refinery (including Plant 2).** This permit includes requirements for the Plants 1 and 3 tanks, while the Plant 2 permit (95OPAD108) includes requirements for the Plant 2 tanks.

Compliance with the VOC emission limitation shall be monitored as follows:

70.1.1.1 Tank degassing means the process of removing volatile organic compound vapors from a storage tank.

70.1.1.2 Emissions from tank cleaning and degassing shall be calculated for each tank cleaning and/or degassing event using tank specific contents, dimensions and type, as well as the duration of the event in using a TankESP version based on the June 2020 version of AP-42, Chapter 7.1. Emissions shall be estimated for each step, as applicable for each tank cleaning and/or degassing event. Note that if a new version of AP-42, Chapter 7.1 is published, Suncor may be required to modify this condition to include the new calculation methodologies to calculate emissions.

- Roof Landings (standing idle losses) – vapors to be routed to the thermal oxidizer
- Vapor Space Purge - vapors to be routed to the thermal oxidizer

- Stock Removal (continued forced ventilation) – vapors to be routed to the thermal oxidizer
- Diesel Flush (continued forced ventilation) – vapors to be routed to the thermal oxidizer
- Sludge Removal (if continued forced ventilation used) – uncontrolled vapors

A control efficiency of 95% may be applied to the calculated emissions in each step, except sludge removal, provided the thermal oxidizer is operated in accordance with the requirements in Condition 70.3.

Records shall be retained for each tank cleaning and/or degassing event indicating tank contents, dimensions and type, which of the above steps were conducted during the event, the duration of each step and the total duration of the event.

70.1.1.3 Emissions from combustion of propane/LPG in the TO for each tank cleaning and/or degassing event shall be calculated using an emission factor of 0.011 lb/MMBtu (from AP-Section 1.5 (dated 7/08), Table 1.5-1, converted to lb/MMBtu based on a propane heat content of 91.5 MMBtu/1000 gal per footnote a) and the quantity of propane/LPG consumption as required by Condition 70.5.1.

Emissions from tank cleaning and/or degassing vapors (Condition 70.1.1.2) and combustion of propane/LPG in the thermal oxidizer (Condition 70.1.1.3) shall be summed together for total VOC emissions from each tank cleaning and/or degassing event. Total VOC emissions from each tank cleaning and/or degassing event for the month conducted under the provisions of this permit, as well as any tank cleaning and/or degassing events conducted under the provisions of Suncor's Plant 2 permit (95OPAD108) shall be summed together to determine the total monthly emissions. Total monthly emissions shall be calculated by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

For purposes of APEN reporting, only monthly emissions from tank cleaning and/or degassing events conducted under the provisions of this permit shall be summed together to determine annual (calendar year) emissions for reporting on AIRS pt 160.

70.1.2 NO_X and CO emissions from the **thermal oxidizer** shall not exceed the limits listed in the above summary table. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 based on requested emissions indicated on the APEN submitted on February 25, 2022.) **This limit includes emissions from tank cleaning and/or degassing of tanks located throughout the refinery.** This permit includes requirements for the Plants 1 and 3 tanks, while the Plant 2 permit (95OPAD108) includes requirements for the Plant 2 tanks.

Compliance with the annual limits shall be monitored as follows:

Emissions from each tank cleaning and/or degassing event shall be by calculated using the emission factors included in the above summary table (from AP-42, Section 1.5 (dated 7/08), Table 1.5-1 for propane, converted to lb/MMBtu based on a heat content of 91.5 MMBtu/10^3 gal) and the quantity of propane/LPG combusted during the event (as required by Condition 70.5.1) in the following equation:

Emissions (ton/mo) = [EF (lb/MMBtu) x propane combusted (MMBtu/mo)]/2000 lb/ton

Emissions from each tank cleaning and/or degassing event for the month conducted under the provisions of this permit, as well as any tank cleaning and/or degassing events conducted under the provisions of Suncor's Plant 2 permit (95OPAD108) shall be summed together to determine the total monthly emissions. Total monthly emissions shall be determined by the end of the subsequent month and used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

For purposes of APEN reporting only monthly emissions from tank cleaning and/or degassing events conducted under the provisions of this permit shall be summed together to determine annual (calendar year) emissions for reporting on AIRS pt 315.

70.1.3 For APEN reporting and fee purposes, PM, PM_{10} and SO_2 emissions from the **thermal oxidizer** shall be calculated monthly. Monthly emissions shall be summed to obtain calendar year emissions for APEN reporting purposes. Monthly emissions shall be calculated as follows:

70.1.3.1 PM and PM_{10} emissions shall be calculated monthly using the emission factors included in the above summary table (from AP-42, Section 1.5 (dated 7/08), Table 1.5-1 for propane, converted to lb/MMBtu based on a heat content of 91.5 MMBtu/10^3 gal) and the monthly quantity of propane combusted for tank cleaning and/or degassing events conducted under the provisions of this permit (as required by Condition 70.5.3) in the equation in Condition 70.1.2.

70.1.3.2 Monthly emissions of SO_2 shall be determined by summing daily SO_2 emissions (as required by Condition 70.2) from tank cleaning and/or degassing events conducted under the provisions of this permit.

70.2 Sulfur dioxide emissions from the **thermal oxidizer** shall be included when evaluating compliance with the Colorado Regulation No. 1 emission limit set forth in Condition 38.1 of this permit.

Daily SO_2 emissions from the thermal oxidizer shall be calculated during each tank degassing and/or cleaning event conducted under the provisions of this permit using the following equations:

SO_2 from thermal oxidizer (lb/day) = SO_2 from degassing (lb/day) + SO_2 from propane/LPG combustion (lb/day)

<u>SO_2 from degassing</u>

SO_2 (lb/day) = [H_2S concentration (ppm) / 385.3 scf/lb-mole x 64 lb SO_2/lb-mole H_2S x degassing vapor flow to the thermal oxidizer (scf/day) x MMscf/10^6 scf]

Where: H_2S concentration = concentration in ppm from the most recent sample required by Condition 70.6.3

<u>SO_2 from propane/LPG combustion</u>

SO_2 (lb/day) = EF (lb/MMBtu) x daily propane/LPG combusted (MMBtu/day)

Where: EF = 1.97×10^{-4} (from AP-42, Section 1.5 (dated 7/08), Table 1.5-2 converted to lb/MMBtu based on a heat content of 91.5 MMBtu/10^3 gal per footnote a, assumes sulfur content of propane = 0.2 gr/100 scf)
Propane/LPG combusted as required by Condition 70.5.1

70.3 Emissions from cleaning and/or degassing tanks shall at all times be routed through a closed vent system to a thermal oxidizer (TO), as required by Condition 70.4, except during sludge removal (see Condition 70.1.1.2). The TO shall meet the following requirements:

70.3.1 The TO shall have a design rate of no more than 20 million Btu per hour. The permittee shall maintain records of the following for any TO used for tank degassing: manufacturer, model, serial number, date the unit was manufactured, design rate and contractor operating the unit.

70.3.2 For purposes of assuring compliance with the annual VOC emission limitation in Condition 70.1.1, the TO shall be operated such that the inlet temperature shall not be less than 1400 ºF. The temperature shall be monitored as specified in the CAM plan included in Appendix M of this permit.

70.4 Cleaning and Degassing of tanks is subject to RACT requirements for VOC. (Colorado Regulation No. 3, Part B, Section III.D.2.a). (Colorado Regulation No. 3, Part B, Section III.D.2.a). RACT has been determined to be use of a TO meeting the requirements in Condition 70.3 and the emission limitations in Condition 70.1.1.

70.5 Propane/LPG consumption for the TO shall not exceed 38,400,000,000 Btu per year. (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 based on requested throughput indicated on the APEN submitted on February 25, 2022.)

Compliance with the annual limit will be monitored as follows:

70.5.1 Consumption of propane/LPG shall be recorded daily during each tank cleaning and/or degassing event using the fuel meter and/or other necessary records. The Btu content of the propane/LPG shall be presumed to be 91.5 MMBtu/1000 gallons. Daily quantities of propane/LPG consumed for the tank degassing and/or cleaning event shall be summed to determine total propane/LPG consumed for the event.

70.5.2 Propane/LPG consumption from each tank cleaning and/or degassing event for the month conducted under the provisions of this permit, as well as any tank cleaning and/or degassing events conducted under the provisions of Suncor's Plant 2 permit (95OPAD108) shall be summed together to determine the total monthly quantity of propane/LPG consumed. Monthly quantities of total propane/LPG consumption shall be used in a rolling twelve month total to monitor compliance with the annual limitation. Each month a new twelve month rolling total shall be calculated using the previous twelve months data.

70.5.3 For purposes of APEN reporting, only monthly propane/LPG combustion from tank cleaning and/or degassing events conducted under the provisions of this permit shall be summed together to determine annual (calendar year) propane LPG usage for reporting on AIRS pt 160.

70.6 The TO is subject to NSPS requirements as follows:

70.6.1 A TO that commenced construction, reconstruction or modification prior to May 14, 2007, is considered a fuel gas burning device and is subject to the requirements in 40 CFR Part 60, Subpart J, specifically, the fuel gas limitation set forth in Condition 45.3.1. In lieu of installing the continuous H_2S monitoring system required by Condition 45.4.3, compliance with the fuel gas limitation shall be monitored in accordance with the alternative monitoring plan set forth in Condition 70.6.3 (approved by EPA in a December 17, 2013 letter).

70.6.2 A TO that commenced construction, reconstruction or modification on or after May 14, 2007, is considered a fuel gas burning device and is subject to the requirements in 40 CFR Part 60, Subpart Ja, specifically, the fuel gas limitations set forth in Condition 46.1.1. In lieu installing the continuous H_2S monitoring system required by Condition 46.14, compliance with the fuel gas limitation shall be monitored in accordance with the alternative monitoring plan set forth in Condition 70.6.3 (approved by EPA in a December 17, 2013 letter).

70.6.3 Compliance with the fuel gas limitations in Conditions 70.6.1 and 70.6.2, shall be monitored as follows:

70.6.3.1 The permittee shall use either H_2S colorimetric tube testing or a portable H_2S meter to determine the concentration of H_2S in gases entering each mobile (portable) thermal oxidizer unit (the "Grab Sample"). Each Grab Sample shall be taken at the inlet to each mobile (portable) thermal oxidizer unit.

70.6.3.2 For each discrete [individual tank] degassing event, the permittee shall perform a Grab Sample within 30 minutes of routing tank vapors to each mobile (portable) thermal oxidizer unit (the "Initial Grab Sample").

70.6.3.3 If the initial Grab Sample indicates an H_2S concentration equal to or less than 162 ppmv, then the inlet gas stream is deemed to meet the H_2S limit of NSPS Subparts J and Ja (Conditions 70.6.1 and 70.6.2) and no further monitoring is required for that discrete degassing event.

70.6.3.4 If the initial Grab Sample indicates an H_2S concentration more than 162 ppmv, then for that discrete [single tank] degassing event, the inlet gas stream is deemed to have exceeded the 230 milligrams per dry standard cubic meter (0.10 grains per dry standard cubic feet) limit of 40 CFR § 60.104(a)(1)) (Condition 70.6.1) and the 162 ppmv limit of 40 CFR § 60.102a(g)(1)(ii) (Condition 70.6.2). Alternatively, the permittee may demonstrate compliance with the H_2S limits in 40 CFR §§ 60.104(a)(1) and 60.102a(g)(1)(ii) (Conditions 70.6.1 and 70.6.2) by averaging three Grab Samples: (i) the initial Grab Sample; (ii) a Grab Sample taken between 61 and 120 minutes after startup of the mobile (portable) thermal oxidizer unit; and (iii) a Grab Sample take between 121 minutes and 180 minutes after startup of the mobile (portable) thermal oxidizer unit. The permittee can use this alternative method of demonstrating compliance only if it has three valid Grab Samples taken within the specified time periods.

70.6.3.5 The permittee shall record the results of each Grab Sample and keep the records of all Grab Samples for at least five years.

70.6.3.6 If the sampling required under this Condition 70.6.3 for a discrete [individual tank] degassing event indicates an exceedance of the H_2S fuel gas limit in Conditions 70.6.1 or 70.6.2 it shall be reported as an excess emission in the reports required by 40 CFR § 60.7(c).

70.6.4 The TO is subject to the NSPS general provisions in 40 CFR Part 60, Subpart A as set forth in Condition 56 of this permit.

70.7 The TO is subject to the opacity limits set forth in Conditions 35.1 and 35.2 of this permit. In the absence of credible evidence to the contrary, compliance with the opacity limits is presumed provided only vapors from tank degassing and/or propane/LPG are combusted and/or oxidized in this unit. Records shall be maintained to verify that only vapors from tank degassing and/or propane/LPG have been combusted and/or oxidized in this unit.

70.8 The requirements of Colorado Regulation No. 3, Part D shall apply to tank cleanings and/or degassing at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation (Colorado Regulation No. 3, Part D, Section V.A.7.b).

With respect to this Condition 70.8, Colorado Regulation No. 3, Part D requirements may apply to future modifications if the emission limitations are modified to equal or exceed the following thresholds:

Pollutant	Program	Emissions (tons/yr)		Comment/ Explanation
		Threshold	Current Permit Limit	
VOC	NANSR	25[1]	17.2	

[1]Indicates the NANSR significance level for a serious ozone nonattainment area. The area was classified as a serious ozone nonattainment area on January 27, 2020, and severe ozone nonattainment area on November 7, 2022.

70.9 Beginning on the date the area in which the source is located is reclassified as a severe ozone non-attainment area, the tank cleaning and degassing TO is subject to the CAM requirements with respect to the VOC emission limit identified in Condition 70.1.1. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 60 and the CAM plan in Appendix M.

71. Miscellaneous Process Vents – MPVs

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
MACT	71.1	Group 1 MPVs shall be routed to a flare		See 40 CFR Part 63 Subpart CC (Condition 53)	
		Prior to venting to atmosphere, maintenance vents shall meet one of the following: Vapor LEL < 10% If vapor LEL cannot be measured, equipment pressure reduce to 5 psig or less Equipment VOC content < 72 pounds For equipment containing pyrophoric catalyst: vapor LEL <20%, except for one event per year not to exceed 35%			

Group 1 MPVs are routed to a flare. For maintenance vents, prior to venting to atmosphere process liquids are removed or equipment is depressured to a control device, fuel gas system or back to the process until one of the conditions in 63.643(c)(1) (Condition 53.14.1) are met. Emissions from MPVs emitted to atmosphere are below the APEN de minimis level.

Miscellaneous process vents are defined in 40 CFR Part 63 Subpart CC §63.641 and include maintenance vents. Process vents can be designated as maintenance vents if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service.

71.1 Miscellaneous process vents are subject to the requirements in 40 CFR Part 63 Subpart CC as set for in Condition 53 of this permit.

72. Reasonably Available Control Technology for Combustion Equipment in the 8-Hour Ozone Control Area: NO_X Emission Limitations; Colorado Regulation No. 26, Part B, Sections II.A.2, 4, 5, 6 and 7 (excluding paragraph 7.f)

These requirements apply to Boilers B-4, B-6 and B-8 and Process Heaters with a design heat input rate greater than or equal to 5 MMBtu/hr.

Note that the language below is from Colorado Regulation No. 26, adopted by the Colorado Air Quality Control Commissions (AQCC) on December 15, 2023 (effective February 14, 2024). However, if revisions to Colorado Regulation No. 26, Part B, Section II.A are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part E, Section II.A.

72.1 **Exemptions** (Regulation No. 26, Part B, Section II.A.2)

The following stationary combustion equipment are exempt from the emission limitation requirements of Section II.A.4., the compliance demonstration requirements in Section II.A.5., and the related recordkeeping and reporting requirements of Sections II.A.7.a-e. and II.A.8, but these sources must maintain any and all records necessary to demonstrate that an exemption applies. These records must be maintained for a minimum of five years and made available to the Division upon request. Qualifying for an exemption in this section does not preclude the combustion process adjustment requirements of Section II.A.6. (Condition 73), when required by II.A.6.a (Condition 73.1.1).

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of this Section II.A. as expeditiously as practicable but no later than 36 months after any exemption no longer applies. Additionally, once stationary combustion equipment that is not equipped with CEMS or CERMS no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations of Section II.A.4. (Regulation No. 26, Part B, Section II.A.2)

72.1.1 Any stationary combustion equipment whose utilization is less than (Regulation No. 26, Part B, Section II.A.2.a)

72.1.1.1 20% of its capacity factor on an annual average basis over a 3-year rolling period for boilers. (Regulation No. 26, Part B, Section II.A.2.a.(i))

72.1.2 Any stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx on a calendar year basis. (Regulation No. 26, Part B, Section II.A.2.d)

Note that for heaters H-6 and H-33, the recordkeeping requirements are met by meeting the requirements in Conditions 11.1 and 18.1.

72.1.3 Any stationary combustion equipment subject to a federally enforceable work practice or emission control requirement contained in this Regulation Number 7, Sections III.A. through III.B. or Regulation 23. (Regulation No. 26, Part B, Section II.A.2.f)

Note that this exemption does not apply until approval of the adopted by the AQCC into Regulation No. 23 (effective January 30, 2022) are approved into Colorado's Round 2 Regional Haze SIP.

72.2 **Emission limitations** (Regulation No. 26, Part B, Section II.A.4)

By October 1, 2021, or the applicable date in Section II.A.4.g. for process heaters (Conditions 72.2.2 and 72.2.3), no owner or operator of stationary combustion equipment specified in Section II.A.1.a. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.b.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified. (Regulation No. 26, Part B, Section II.A.4, first paragraph)

Boilers (Regulation No. 26, Part B, Section II.A.4.a)

72.2.1 For a gaseous fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen. (Regulation No. 26, Part B, Section II.A.4.a.(i))

Process Heaters (Regulation No. 26, Part B, Section II.A.4.g)

72.2.2 Except as specified in Section II.A.4.g.(ii) (Condition 72.2.3), by May 1, 2022, process heaters must comply with the following NOx emission limits in the table below. (Colorado Regulation No. 26, Part B, Section II.A.4.g.(i))

Heat Input Rate (MMBtu/hr	Fuel Type	NO_X limit (lb/MMBtu)
$\geq$ 5 and < 100	Natural Gas	0.05

72.2.3 Process heaters that require a permitting action or facility shut-down to comply with the NOx emission limits in the table in Condition 72.2.2 must comply by May 31, 2023. (Colorado Regulation No. 26, Part B, Section II.A.4.g.(ii))

72.3 **Compliance demonstration** (Regulation No. 26, Part B, Section II.A.5)

72.3.1 By October 1, 2021, for stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, except for process heaters specified in Section II.A.4.g., the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in this Section II.A.5. (Regulation No. 26, Part B, Section II.A.5.a.(i))

Continuous emission monitoring (Regulation No. 26, Part B, Section II.A.5.b.(i))

72.3.2 Owners or operators of an affected unit subject to a NOx emission limit in Sections II.A.4.a.(i) through II.A.4.a.(iii) (Condition 72.2.1), II.A.4.c., or II.A.4.d. must install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.b.(i). Owners or operators of affected units' subject to a NOx emission limit in Sections II.A.4.b., II.A.4.e., or II.A.4.g. (Condition 72.2.2) may install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.b.(i) in lieu of performance testing pursuant to Section II.A.5.b.(ii). (Regulation No. 26, Part B, Section II.A.5.b.(i)(A))

72.3.2.1 For an affected unit that is not equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with 40 CFR Part 60 (July 19, 2018) or Part 75 (July 19, 2018), the owner or operator must install, operate, and maintain a NOx CEMS or CERMS that measures emissions in terms of the applicable emission limitation and must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable provisions of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018). The owner or operator must use the following methodology for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section II.A.4. (Regulation No. 26, Part B, Section II.A.5.b.(i)(A)(3))

a. A unit operating day is a calendar day when any fuel is combusted in the affected unit. (Regulation No. 26, Part B, Section II.A.5.b.(i)(A)(3)(a))

b. 30-day rolling average emission rates must be calculated as the arithmetic average emissions rates determined by the CEMS or CERMS for all hours the affected unit combusted any fuel from the current unit operating day and the prior 29 unit operating days. (Regulation No. 26, Part B, Section II.A.5.b.(i)(A)(3)(b))

Initial and periodic performance testing (Regulation No. 26, Part B, Section II.A.5.b.(ii))

72.3.3 An owner or operator of a process heater subject to a NOx emission limit in Section II.A.4.g. must (Regulation No. 26, Part B, Section II.A.5.b.(ii)(B):

72.3.3.1 For natural gas-fired and refinery gas-fired process heaters greater than or equal to 100 MMBtu/hr, conduct an initial performance test in accordance with Sections II.A.5.b.(ii)(C)(1), II.A.5.b.(ii)(C)(4), and II.A.5.b.(ii)(D) by April 1, 2022, or by November 30, 2023, for process heaters specified in Section II.A.4.g.(ii), and conduct subsequent performance tests in accordance with Sections II.A.5.b.(ii)(C)(1), II.A.5.b.(ii)(C)(4), and II.A.5.b.(ii)(D) every 2 years thereafter. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(B)(1))

72.3.3.2 For natural gas-fired process heaters greater than or equal to 50 MMBtu/hr and less than 100 MMBtu/hr, conduct an initial performance test in accordance with Sections II.A.5.b.(ii)(C)(1), II.A.5.b.(ii)(C)(4), and II.A.5.b.(ii)(D) by April 1, 2022, or by November 30, 2023, for process heaters specified in Section II.A.4.g.(ii), and comply with the combustion process adjustment requirements in Section II.A.6. thereafter. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(B)(2))

72.3.3.3 For natural gas-fired process heaters greater than or equal to 5 MMBtu/hr and less than 50 MMBtu/hr and refinery gas-fired process heaters greater than or equal to 5 MMBtu/hr and less than 100 MMBtu/hr, comply with the combustion process adjustment requirements in Section II.A.6. ((Regulation No. 26, Part B, Section II.A.5.b.(ii)(B)(3))

72.3.3.4 For a group of process heaters that vent to a common stack, the owner or operator may either assess compliance for the heaters individually by performing a separate emission test of each heater in the duct leading from the heater to the common stack or may perform a single emission test in the common stack. The owner or operator must include in the test protocol for these units a definition of representative conditions for performance testing purposes. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(B)(4))

72.3.3.5 Performance tests conducted in accordance with Sections II.A.5.b.(ii)(D)(1) through II.A.5.b.(ii)(D)(3) and II.A.5.b.(ii)(E) within three (3) years of the applicable performance testing date in Sections II.A.5.b.(ii)(B)(1) or II.A.5.b.(ii)(B)(2) will satisfy the initial performance testing requirement. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(B)(6))

72.3.4 General test requirements – Sections II.A.5.b.(ii)(C) and (D)

72.3.4.1 A performance test is not required for a fuel used only for startup or for a fuel constituting less than 2% of the unit's annual heat input, as determined at the end of each calendar year. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(D)(1))

72.3.4.2 Initial performance test must include a determination of the capacity load point of the unit's maximum NOx emissions rate based on one 30-minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, and 70 to 100%. Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NOx emissions rate. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(D)(2))

72.3.4.3 Performance tests must determine compliance with Section II.A.4. based on the average of three 60-minute test runs performed at the capacity load determined in Section II.A.5.b.(ii)(D)(2). (Regulation No. 26, Part B, Section II.A.5.b.(ii)(D)(3))

72.3.4.4 Initial performance test must be conducted at both high and low load capacity. If site operations do not allow testing at high and low loads, the initial performance test must be conducted at the highest achievable load that site conditions allow. The owner or operator must submit a summary of six months of operating performance with the test protocol supporting the testing load(s). Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NOx emissions rate. Performance tests must determine compliance based on the average of three 60-minute test runs. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(D)(4))

72.3.4.5 All performance tests must be conducted in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C. (Regulation No. 26, Part B, Section II.A.5.b.(ii)(F)

72.3.5 Where measuring fuel use is necessary to calculate an emission rate in the units of the applicable standard, fuel flowmeters must be installed, calibrated, maintained, and operated according to manufacturer's instructions for measuring and recording heat input in terms of the applicable emission limitation. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of 40 CFR Part 75, Appendix D are acceptable for demonstrating compliance with this section. The installation of fuel flowmeters is not required where emissions of NOx in terms of the applicable standard can be calculated in accordance with applicable provisions of EPA Method 19 or where the standard is concentration based (e.g. parts per million dry volume corrected for oxygen). (Regulation No. 26, Part B, Section II.A.5.b.(iv))

72.4 **Recordkeeping** – Regulation No. 26, Part B, Section II.A.7

The following records must be kept for a period of five years and made available to the Division upon request (Regulation No. 26, Part B, Section II.A.7):

72.4.1 The type and amount of fuel used. (Regulation No. 26, Part B, Section II.A.7.c)

72.4.2 The stationary combustion equipment's annual capacity factor on a calendar year basis. (Regulation No. 26, Part B, Section II.A.7.d)

72.4.3 All records generated to comply with the reporting requirements contained in Section II.A.8. (Regulation No. 26, Part B, Section II.A.7.e)

72.4.4 All sources qualifying for an exemption under Section II.A.2. must maintain all records necessary to demonstrate that an exemption applies. (Regulation No. 26, Part B, Section II.A.7.g)

72.5 **Reporting** – Regulation No. 26, Part B, Section II.A.8

72.5.1 For affected units demonstrating compliance with Section II.A.4. using CEMS or CERMS in accordance with Section II.A.5.c.(i)(A), the owner or operator must submit to the Division the following information (Regulation No. 26, Part B, Section II.A.8.a):

72.5.1.1 Quarterly or semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual or quarterly period, as applicable. Excess emissions means emissions that exceed the applicable limitations contained in Section II.A.4. Excess emission reports must include the information specified in 40 CFR Part 60, Section 60.7(c) (July 1, 2018). (Regulation No. 26, Part B, Section II.A.8.a.(i)) Excess emission reports shall be submitted quarterly and meet the content requirements in Condition 59.4.1.

72.5.2 For affected units demonstrating compliance with Section II.A.4 using performance testing pursuant to Section II.A.5.c.(ii)(C), the owner or operator must submit to the Division the following information (Regulation No. 26, Part B, Section II.A.8.b):

72.5.2.1 Performance test or portable analyzer testing reports within 60 days after completion of the performance test program. All performance test or portable analyzer testing reports must determine compliance with the applicable emission limitations set by Section II.A.4. (Regulation No. 26, Part B, Section II.A.8.b.(i))

73. Reasonably Available Control Technology for Combustion Equipment in the 8-Hour Ozone Control Area: Combustion Process Adjustment and Associated Recordkeeping Requirements, Colorado Regulation No. 26, Part B, Sections II.A.6 and II.A.7.f

These requirements apply to any boilers, process heaters or engines with actual, uncontrolled NO_X emissions equal to or greater than 5 tons per year (calendar year).

Note that the language below is from Colorado Regulation No. 7, adopted by the Colorado Air Quality Control Commissions (AQCC) on December 15, 2023 (effective February 14, 2024). However, if revisions to Colorado Regulation No. 7, Part B, Section II are published at a later date, the owner or operator is subject to the requirements contained in the revised version of Part E, Section II.

73.1 **Combustion Process Adjustment Requirements** (Regulation No. 26, Part B, Section II.A.6)

73.1.1 Applicability (Regulation No. 26, Part B, Section II.A.6.a)

73.1.1.1 As of January 1, 2017, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016. (Regulation No. 26, Part B, Section II.A.6.a.(i))

73.1.1.2 As of May 1, 2020, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, that is not already subject as provided under Section II.A.6.a.(i) (Regulation No. 6, Part E, Section II.A.6.a.(ii))

Note that the emission threshold is based on calendar year actual emissions. Since only boilers, process heaters and engines are located at this facility, only the requirements related to that equipment has been included in the permit.

73.1.2 **Combustion Process Adjustment** (Regulation No. 26, Part B, Section II.A.6.b)

73.1.2.1 When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, the owner or operator must conduct the following inspections and adjustments of boilers and process heaters, as applicable (Regulation No. 26, Part B, Section II.A.6.b.(i)):

a. Inspect the burner and combustion controls and clean or replace components as necessary. (Regulation No. 26, Part B, Section II.A.6.b.(i)(A))

b. Inspect the flame pattern and adjust the burner or combustion controls as necessary to optimize the flame pattern. (Regulation No. 26, Part B, Section II.A.6.b.(i)(B))

c. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. (Regulation No. 26, Part B, Section II.A.6.b.(i)(C))

d. Measure the concentration in the effluent stream of carbon monoxide and nitrogen oxide in ppm, by volume, before and after the adjustments in Sections II.A.6.b.(i)(A) through (C). Measurements may be taken using a portable analyzer. (Regulation No. 26, Part B, Section II.A.6.b.(i)(D))

73.1.2.2 The owner or operator of a stationary internal combustion engine must conduct the following inspections and adjustments, as applicable (Regulation No. 26, Part B, Section II.A.6.b.(iv)):

a. Change oil and filters as necessary. (Regulation No. 26, Part B, Section II.A.6.b.(iv)(A))

b. Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary. (Regulation No. 26, Part B, Section II.A.6.b.(iv)(B))

c. Inspect spark plugs and replace as necessary. (Regulation No. 26, Part B, Section II.A.6.b.(iv)(C))

73.1.2.3 The owner or operator must operate and maintain the boiler, duct burner, process heater, stationary combustion turbine, stationary internal combustion engine, dryer, furnace, or ceramic kiln consistent with manufacturer's specifications, if available, or good engineering and maintenance practices. (Regulation No. 26, Part B, Section II.A.6.b.(vii))

73.1.2.4 Frequency (Regulation No. 26, Part B, Section II.A.6.b.(viii))

a. The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, must conduct the initial combustion process adjustment by April 1, 2017. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016) to satisfy the requirement to conduct an initial combustion process adjustment by April 1, 2017. (Regulation No. 26, Part B, Section II.A.6.b.(viii)(A))

b. The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, must conduct the initial combustion process adjustment by May 1, 2020. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) to satisfy the requirement to conduct an initial combustion process adjustment by May 1, 2020. (Regulation No. 26, Part B, Section II.A.6.b.(viii)(B))

c. The owner or operator must conduct subsequent combustion process adjustments at least once every twelve (12) months after the initial combustion adjustment, or on the applicable schedule according to Sections II.A.6.c.(1). or II.A.6.c.(ii). (Regulation No. 26, Part B, Section II.A.6.b.(viii)(F))

d. Beginning January 1, 2022, the owner or operator of process heaters at a refinery must conduct subsequent combustion process adjustments at least once every six (6) months after the initial combustion adjustment, or on the applicable schedule according to Sections II.A.6.c.(i). or II.A.6.c.(ii). (Regulation No. 3, Part E, Section II.A.6.b.(viii)(G))

73.1.3 As an alternative to the requirements described in Sections II.A.6.b.(i) through II.A.6.b.(viii) (Regulation No. 26, Part B, Section II.A.6.c):

73.1.3.1 The owner or operator may conduct the combustion process adjustment according to the manufacturer recommended procedures and schedule; (Regulation No. 26, Part B, Section II.A.6.c.(i)); or

73.1.3.2 The owner or operator of combustion equipment that is subject to and required to conduct a periodic tune-up or combustion adjustment by the applicable requirements of a New Source Performance Standard in 40 CFR Part 60 (July 1, 2022) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (July 1, 2022) may conduct tune-ups or adjustments according to the schedule and procedures of the applicable requirements of 40 CFR Part 60 (July 1, 2022) or 40 CFR Part 63 (July 1, 2022). (Regulation No. 26, Part B, Section II.A.6.c.(ii))

73.2 **Recordkeeping Requirements** (Regulation No. 26, Part B, Section II.A.7)

The following records must be kept for a period of five years and made available to the Division upon request (Regulation No. 26, Part B, Section II.A.7):

73.2.1 For stationary combustion equipment subject to the **combustion process adjustment requirements** in Section II.A.6., the following recordkeeping requirements apply (Regulation No. 26, Part B, Section II.A.7.f):

73.2.1.1 The owner or operator must create a record once every calendar year identifying the combustion equipment at the source subject to Section II.A. and including for each combustion equipment: (Regulation No. 26, Part B, Section II.A7.f .(i)):

a. The date of the adjustment (Regulation No. 26, Part B, Section II.A.7.f.(i)(A));

b. Whether the combustion process adjustment under Sections II.A.6.b.(i) through II.A.6.b.(vi) was followed, and what procedures were performed (Regulation No. 26, Part B, Section II.A.7.f.(i)(B));

c. Whether a combustion process adjustment under Sections II.A.6.c.(i). and II.A.6.c.(ii). was followed, what procedures were performed, and what New Source Performance or National Emission Standard for Hazardous Air Pollutants applied, if any Regulation No. 26, Part B, Section II.A.7.f.(i)(C)); and

d. A description of any corrective action taken. (Regulation No. 26, Part B, Section II.A.7.f.(i)(D))

e. If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation. (Regulation No. 26, Part B, Section II.A.7.f.(i)(E))

73.2.1.2 The owner or operator must retain manufacturer recommended procedures, specifications, and maintenance schedule if utilized under Section II.A.6.c.(i). for the life of the equipment. (Regulation No. 26, Part B, Section II.A.7.f .(ii))

73.2.1.3 As an alternative to the requirements described in Section II.A.7.f.(i), the owner or operator may comply with applicable recordkeeping requirements related to combustion process adjustments conducted according to a New Source Performance Standard in 40 CFR Part 60 (July 1, 2022) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (July 1, 2022). (Regulation No. 26, Part B, Section II.A.7.f .(iii))

SECTION III - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§I.A.4, V.D., & XIII.B and §25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based upon the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Applicable Requirement	Justification
Colorado Regulations	
FCCU only: Colorado Regulation No, 1, Section IV.D.2 – CEM Requirements for FCCUs at Petroleum Refineries	The permittee was granted exemption from the CEM requirements by meeting the demonstration correlation requirements listed in Section IV.D.3, and obtaining Division approval of the exemption
T67, T70, T74, T75, T77, T78, T80, T776, T778, T1, T34, T55, T58, T96, T97, T116, T775, T2010, T4501, T2, T3, T62, T94, T774, T777, T2006, T3201, T7208: Colorado Regulation No. 24, Part B, Section IV.B.3.	These tanks are not petroleum liquid storage tanks less than 40,000 gallons.
T67, T70, T75, T77, T78, T80, T776, T778, T1, T34, T55, T58, T775, T2010, T4501, T62, T774, T777: Colorado Regulation No. 24, Part B, Section IV.B.2.a.	These tanks are not fixed roof or internal floating roof tanks.
T74, T96, T97, T116, T2, T3, T94, T2006, T3201, T7208: Colorado Regulation No. 24, Part B, Section IV.B.2.c	These tanks are not external floating roof tanks.
T67, T70, T74, T75, T77, T78, T80, T776, T778, T1, T34, T55, T58, T96, T97, T116, T775, T2010, T4501, T2, T3, T62, T94, T774, T777, T2006, T3201, T7208: Colorado Regulation No. 24, Part B, Section IV.C	These requirements apply to loading operations. Tanks are not loading equipment.
T67, T70, T74, T75, T77, T78, T80, T776, T778, T1, T34, T55, T58, T96, T97, T116, T775, T2010, T4501, T2, T3, T62, T94, T774, T777, T2006, T3201, T7208: Colorado Regulation No. 24, Part B, Section IV.D.2.a	These requirements apply to loading tank trucks. Tanks are not loading equipment.
T67, T70, T74, T75, T77, T78, T80, T778, T1, T34, T55, T96, T97, T116, T2010, T4501, T2, T3, T62, T94, T774, T777, T2006, T3201, T7208: Colorado Regulation No. 24, Part B, Section V	These tanks are not crude oil tanks.
Main Plant (F1) and Asphalt Plant (F2) Flares: Colorado Regulation No. 1, Section III.A and Colorado Regulation No. 6, Part B, Section II	Flares are not considered fuel burning equipment.

Applicable Requirement	Justification
Boilers B4, B6 and B8. Colorado Regulation No. 6, Part B, Section IV.B.1.	These requirements do not apply, since these boiler are rated at less than 250 MMBtu/hr.
New Source Performance Standards (NSPS)	
Facility Wide: 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Facility does not include any steam generating units that were not existing sources as of the June 9, 1989 effective date of NSPS Subpart Db, and that have a maximum design heat input capacity of 29 MW (100 MMBtu/hour) or less, but greater than or equal to 2.9 MW (10 MMBtu/hour)
Facility Wide: 40 CFR Part 60, Subpart NNN – Standards of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	Facility is not a process unit that produces any of the chemicals listed in 40 CFR 60.667 and does not include any distillation facility that emits a gas stream directly or indirectly to the atmosphere
Facility Wide: 40 CFR Part 60 Subpart GG, Standards of Performance for Stationary Combustion Turbines.	There are no combustion turbines located at the facility.
Facility Wide: 40 CFR Part 60 Subpart E, Standards of Performance for Incinerators.	There are no solid waste incinerators located at the facility.
T67, T70, T74, T75, T77, T78, T80, T778: 40 CFR Part 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquid for Which Construction, Reconstruction or Modification Commenced After June 11, 1973 and Prior to May 19, 1978.	Construction commenced prior to June 11, 1973.
T1, T67, T70, T74, T75, T77, T78, T80, T778: 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984	Construction commenced prior to July 23, 1984.
T67, T70, T74, T75, T77, T78, T80, T778: 40 CFR Part 60 Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.	Construction commenced prior to November 18, 1980.
T1, T34, T55, T58, T96, T97, T116, T775, T2010, T4501, T2, T3, T62, T94, T774, T778, T7208: 40 CFR Part 60 Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.	Tanks are not asphalt storage tanks.
T2, T3, T62, T94, T774, T2006, T3201: 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984	Tanks store liquids with a maximum true vapor pressure less than 3.5 kPa.
Maximum Achievable Control Technology (MACT)	
Facility Wide: 40 CFR Part 63, Subpart F – National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry	Facility does not manufacture as a primary product, or use as a reactant or manufacture as a product, or co-product, any of the chemicals or organic hazardous air pollutants specified under 40 CFR 63.100

Applicable Requirement	Justification
Facility Wide: 40 CFR Part 63, Subpart Q – National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	Facility does not include any industrial process cooling towers that are operated with chromium-based water treatment chemicals that were not existing sources on the September 8, 1994 effective date of 40 CFR Part 63, Subpart Q
Facility Wide: 40 CFR Part 63, Subpart T – National Emission Standards for Halogenated Solvent Cleaning	Facility does not include any batch vapor, in-line vapor, in-line cold, and batch cold solvent cleaning machine that uses any solvent containing methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, or chloroform, or any combination of these halogenated HAP solvents, in a total concentration greater than 5 percent by weight, as a cleaning and/or drying agent
Facility Wide, Except for the Truck Rack (R102): 40 CFR Part 63, Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants for Site Remediation	The facility's site remediation is required by an order authorized under RCRA section 7003. (40 CFR 63.7881(b)(3)) In the event that site remediation at the remainder of the refinery is no longer subject to a RCRA order, the provisions in 40 CFR Part 63 Subpart GGGGG apply.
Facility Wide: 40 CFR Part 63, Subpart EEEE, National Emission Standards for Hazardous Air Pollutants Organic Liquids Distribution (Non-Gasoline)	The loading racks (truck and rail rack), storage tanks and components associated with the storage tanks, loading racks and pipelines between tanks and loading racks do not contain organic liquids. Organic liquids exclude Gasoline (including aviation gasoline), kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oils and fuel oils.
R102 and T7208: 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.	The truck loading rack and flare (R102) is classified under SIC code 5171 and is operated under Suncor Energy (U.S.A.)'s pipeline operation as opposed to refinery operations (SIC code 2911), therefore the requiremets in Subpart CC do not apply (see 63.640(c)(5)). Tank T7208 is associated with the truck loading rack (R102) and therefore is also not subject to these requirements.
T55, T58, T775, T4501, T2, T3, T62, T774, T2006, T3201: 40 CFR Part 63 Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	These requirements do not apply as these tanks do not store gasoline.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§25-7-112 and 25-7-113, C.R.S., or §303 of the federal act, concerning enforcement in cases of emergency;

2.2 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;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with §408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to §114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, §XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Streamlined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield, compliance with the listed permit conditions will serve as a compliance determination for purposes of the associated subsumed requirements.

Permit Condition(s)	Streamlined (Subsumed) Requirements
Construction Permit Requirements	
Section II, Conditions 12.3 and 19.3 (H-10, H-11, H-27 and B-4) and 45.3.1	Construction Permit 90AD053 - fuel sulfur content limit of 0.0026% by weight.
Section II, Conditions 21.3, 46.1.1 and 46.14	Construction Permit 04AD0110, Condition 6 (gases routed to the flare shall not exceed 162 ppmv H_2S on a 3-hr rolling average and compliance with the limit shall be monitored using a continuous fuel gas monitoring system required by T5 permit)
Section II, Conditions 28.3, 46.1.1 and 46.14	Construction Permit 09AD1351, Condition 9 (gases routed to the flare shall not exceed 162 ppmv H_2S on a 3-hr rolling average and compliance with the limit shall be monitored using a continuous fuel gas monitoring system required by T5 permit)
Section II, Conditions 31.2, 46.8 and 46.15	Construction Permit 10AD1768, Condition 9 (gases routed to the flare shall not exceed 162 ppmv H_2S on a 3-hr rolling average and compliance with the limit shall be monitored using a continuous fuel gas monitoring system required by T5 permit)
Colorado Regulations No. 1 and No. 6, Part B Requirements	
Section II, Conditions 22.10.1 and 45.2.	Colorado Regulation No. 1, Section IX (CO emissions from FCCU not to exceed 500 ppmv, on a 1-hr average)
Section II, Condition 8.7.3	Colorado Regulation No. 1, Section VI.B.4.b.(i) [SO_2 emissions shall not exceed 0.8 lb/MMBtu] as applicable to the emergency air compressor engines.
Section II, Condition 36.1	Colorado Regulation No. 6, Part B, Section II.C.2 [particulate matter emissions shall not exceed $0.5(FI)^{-0.26}$ lbs/MMBtu] **– State-Only Requirement.** Note that these requirements did not apply to the following equipment: H-16, H-18, H-20, H-22, H10, H-11, H-27, B6 and B8.
Section II, Condition 38.1	Colorado Regulation No. 6, Part B, Section IV.C.2 [SO_2 emissions from refineries shall not exceed 0.3 lb/barrel] **– State-Only Requirement**
Section II, Condition 56	Regulation No. 6, Part B, Section I [general provisions] **- State-only Requirement** Note that these requirements did not apply to the following equipment: H-16, H-18, H-20, H-22, H10, H-11, H-27, B6 and B8.
Consent Decree and Compliance Order on Consent Requirements	
Section II, Conditions 24.2 and 45.4.3.1.b	Consent Decree (H-01-4430), Paragraph 160 [NSPS Subpart J alternative monitoring methods for flares]
Section II, Conditions 24.2 and 45.4.3.1.b	Compliance Order on Consent, December 17, 2001, paragraph 45 [flare shall meet the requirements in NSPS Subparts A and J].
Section II, Condition 30.2	Compliance Order on Consent, December 17, 2001, paragraph 43 [flare shall meet the requirements in NSPS Subparts A and J].

Permit Condition(s)	Streamlined (Subsumed) Requirements
Section II, Condition 23.9.2	Consent Decree (H-01-4430), Paragraph 91 [breakthrough of carbon canisters defined as 50 ppm VOC]
NSPS Requirements	
Section II, Condition 22.2.1	40 CFR Part 60 Subpart J §60.104(b)(2) and (c), as adopted by reference in Colorado Regulation No. 6, Part A [SO_2 emissions from FCCU shall not exceed 20 lb/ton coke burn-off on a 7-day rolling average]
Section II, Condition 22.2.2	40 CFR Part 60 Subpart J §60.106(g) and (i) [performance test methods for FCCU SO_2 limit in §60.104(b)(2)]
Section II, Condition 53	40 CFR Part 60 Subpart K, as adopted by reference in Colorado Regulation No. 6, Part A [applied to tank T1] – In accordance with the provisions in Section II, Condition 53.28.3 (63.640(n)(5)) source no longer has to comply with these requirements.
NESHAP Requirements	
Section II, Condition 53	40 CFR Part 61 Subpart J, as adopted by reference in Colorado Regulation No. 8, Part A [applied to some components associated with the GBR Unit (F114)] – In accordance with the provisions in Section II, Condition 53.43 (63.640(p)(1)) source no longer has to comply with these requirements.
Regional Haze Requirements (Colorado Regulation No. 23)	
Section II, Condition 29.9	Colorado Regulation No. 23, Section IV.F.3 – Plant 1 Flare Emission Limit (162 ppmv H_2S, on a 3-hr rolling average)
Section II, Conditions 27.1.3 and 27.11	Colorado Regulation No. 23, Sections V.A.1.b, V.A.1.b.(i) and V.A.1.b.(i)(D) [maintain, calibrate and operate NO_X CEMS, calculate hourly NO_X emissions and use in 12-month rolling total]
Section II, Conditions 20.1.2 and 20.13	Colorado Regulation No. 23, Sections V.A.1.d and V.A.1.d.(i)(B) [operate an SO_2 CEMS, calculate SO_2 emissions and use in a 12-month rolling total]
Section II, Conditions 45 and 54	Colorado Regulation No. 23, Section V.A.1.d.(i)(A) [demonstrate compliance with SO_2 limits using procedures in NSPS Subparts A and J and 40 CFR 63.1568]
Section II, Conditions 22.2.2 and 22.4.2 and 59.1.1.4	Colorado Regulation No. 23, Sections V.A.1.e, V.A.1.e.(i)(A) and V.A.1.e.(i)(B) [maintain, calibrate and operate NO_X and SO_2 CEMS, calculate hourly NO_X and SO_2 emissions and use in 365-day rolling average]
Section II, Conditions 14.1 (H-17), 16.1 (H-28, H-29 & H-30) and 18.1 (H-37)	Colorado Regulation No. 23, Section V.A.2.e.(i) [Monthly emission calculations, using specified emission factors] **– with respect to H-17, H-28, H-29, H-30 and H-37 only.**
Section II, Conditions 29.9 and 46	Colorado Regulation No. 23, Section V.A.2.e.(ii) [use NSPS Ja provisions to comply with Plant 1 Flare H_2S limit in Section IV.F.3]
Section II, Conditions 45 and 54	Colorado Regulation No. 23, Section V.B.4.e.(i) [use NSPS A and J and 40 CFR Part 63 60.1564 to comply with FCCU PM requirements]
Section IV, Conditions 22.b. & c	Colorado Regulation No. 23, Section V.C.1 and 2 [Maintain CEMS data and records of QA/QC requirements] **–with respect to H-2101, Boiler B-4, SRU and FCCU.**
Section II, Condition 59.4	Colorado Regulation No. 23, Section V.D, first paragraph [semi-annual excess emission reports] – with respect to H-2101, Boiler B-4 and SRU
Regulation No. 26, Part B, Section II.A Requirements	
Section II, Conditions 19.5.1 & 19.5.3	Regulation No. 26, Part B, Sections II.4.a.(i) and II.A.5.a.(i) [NOx emissions not to exceed 0.2 lb/MMBtu from boiler burning gaseous fuel, comply with limit by October 1, 2021]
Section II, Conditions 19.5.5 thru 19.5.8	Regulation No. 26, Part B, Sections II.A.5.b.(i)(A) and II.A.5.b.(i)(A)(2) [must use NO_X CEMS, if NO_X CEMS required for a Subpart under 40 CFR Part 60, use Subpart operating day, data averaging methodology, and data validation requirements]
Section II, Condition 19.6	Regulation No. 26, Part B, Section II.A.7.c [keep records of type and amount of fuel used]
Section II, Condition 19.5.9.1	Regulation No. 26, Part B, Section II.A.7.d [calculate the annual capacity factor]

Permit Condition(s)	Streamlined (Subsumed) Requirements
Section IV, Conditions 22.b & c	Regulation No. 26, Part B, Section II.A.7.e [maintain all records generated to comply with reporting requirements for 5 years]
Section II, Condition 59.4	Regulation No. 26, Part B, Sections II.A.8.a and a(i) [sources using a CEMS shall submit quarterly or semi-annual excess emission reports]

SECTION IV - General Permit Conditions

Version 5/17/2023

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions - **State-Only as of June 1, 2024**

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and does not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction must notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and must submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification must address the criteria set forth above.

The Affirmative Defense Provision contained in this section is not available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown – **State-Only as of June 1, 2024**

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator’s actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and does not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown must notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and must submit written quarterly notification following the initial occurrence of the excess emissions. The notification must address the criteria set forth above.

The Affirmative Defense Provision contained in this section is not available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division 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 Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

(i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

(ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

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 the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, 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. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

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 specifically provided for in the permit.

8. Fee Payment

Regulation No. 3, 5 CCR 1001-5, Part A, § VI.E., C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

d. Upon a finding by EPA that the 2008 ozone National Ambient Air Quality Standard (NAAQS) nonattainment area fails to attain the 2008 ozone NAAQS by the date the nonattainment area is mandated to reach attainment of the 2008 ozone NAAQS (i.e., 2027, unless granted an extension), major stationary sources shall pay fees in accordance with the provisions in Regulation No. 3, Part A, Section VI.E.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee’s premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

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

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

<u>Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.</u>

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. 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 the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D. A revised APEN shall be filed annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part B § I. Annual fees are based on the most recent APEN on file with the Division.

(i) By January 31, 2024, and by every January 31 thereafter, stationary sources in the ozone nonattainment area with the potential to emit VOC and/or NOx emissions equal to or greater than 25 tons per year (per pollutant) must certify annually through a Division-approved format that annual actual VOC and/or NOx emissions estimates are as reported on Air Pollutant Emission Notices for that certifying year, including per the thresholds defined as significant changes in Regulation No. 3, Part A, § II.C.2.

f. **State-Only requirement.** Owners or operators required to report greenhouse gases pursuant to Regulation Number 22, Part A or Regulation Number 7, Part B, Sections IV. or V. must submit a facility-wide greenhouse gas emissions Air Pollutant Emission Notice, using a Division-approved form, for each facility directly emitting CO2e emissions equal to or greater than 25,000 tpy. Facility-wide greenhouse gas APENS are due on or before December 31, reporting calendar year emissions for the previous year in accordance with the requirements in Regulation No. 3, Part A, § II.A.2.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines 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; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Requirements for Major Stationary Sources

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit’s annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a.(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

25. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

26. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

27. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

28. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

29. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

30. Volatile Organic Compounds

Regulation No. 24, 5 CCR 1001-28, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard, the 8-hour Ozone Control Area, and to northern Weld County and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 24, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 24, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 24, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 24, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

31. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

OPERATING PERMIT APPENDICES

A - INSPECTION INFORMATION
B - MONITORING AND PERMIT DEVIATION REPORT FORMAT
C - COMPLIANCE CERTIFICATION REPORT
D - NOTIFICATION ADDRESSES
E - PERMIT ACRONYMS
F - PERMIT MODIFICATIONS
G – CONSENT DECREE BENZENE, LDAR AND FLARING EVENTS
H – FCCU COMPLIANCE ASSURANCE MONITORING PLAN
I - SITE REMEDIATION MACT (40 CFR PART 63 SUBPART GGGGG) APPLICABILITY DIAGRAM
J - PLANT 1 FCCU OPACITY PLAN
K - PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW AND NON-ATTAINMENT AREA NEW SOURCE REVIEW (NANSR) APPLICABILITY TESTS
L - ANALYSES OF EMISSIONS INCREASES FROM VARIOUS SUNCOR PROJECTS
M- THERMAL AND CATALYTIC OXIDIZER COMPLIANCE ASSURANCE MONITORING PLANS
N - FLARE AND VAPOR COMBUSTOR COMPLIANCE ASSURANCE MONITORING PLANS

*DISCLAIMER:

None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise stated in this permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

APPENDIX A - Inspection Information

Directions to Plant:

The facility is located at 5801 Brighton Boulevard, Commerce City. The Suncor visitor orientation facility is located on 56th Avenue near the Source Crude Unit entrance.

Safety Equipment Required:

Eye Protection (Safety Glasses with Shields)*; Hard Hat*; Safety Shoes; Hearing Protection*; Nomex Coveralls*

*The permittee can provide this equipment at the site for visitors

Facility Plot Plan:

A facility plot plan is not included in the permit at this time.

List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

The asterisk (*) denotes an insignificant activity source category based on the size of the activity, emissions levels from the activity or the production rate of the activity. The owner or operator of individual emission points in insignificant activity source categories marked with an asterisk (*) must maintain sufficient record keeping verifying that the exemption applies. Such records shall be made available for Division review upon request. (Colorado Regulation No. 3, Part C, Section II.E)

Units with emissions less than APEN de minimis - criteria pollutants (Reg 3 Part C.II.E.3.a)*

Liquified petroleum gas (LPG) loading and unloading, as follows:

- Loading of propane and mixed butanes into railcars (VOC < 1 tpy)
- Unloading butane from railcars (VOC < 1 tpy)
- Loading o f LPGs into tank trucks (VOC < 1 tpy)
- Unloading butane tank trucks (VOC < 1 tpy)

WWTS RTO purge valve (VOC emissions < 1 ton/yr)
Soda ash (Tank T335) vent system ($PM/PM_{10}/PM_{2.5}$ emissions < 2 ton/yr)
Cat Poly Unit – catalyst loading, unloading and blowdowns ($PM/PM_{10}/PM_{2.5}$ emissions < 2 ton/yr)

Tank D162	Additives
Tank D163	Additive
Tank T334	Diesel dye
Tank T2004	Bio-diesel – B100 (80,000 gallons)
Tank T2007	Bio-diesel – B100 (80,000 gallons)
Tank T8301	Bio-additives (15,000 gallons)
Tank 7006	Diesel additives (3,000 gallons)

RPC West Zone AS System (VOC < 1 tpy)

Note that emissions from this system must be included in the emission calculations required by Section I, Condition 69.1.

Four (4) gasoline tanks, each tank 500 gal capacity, located at the Plant 1 Fueling Station

T-5501 – rectangular storage tank (2,000 gal capacity) with a 1,500 gal compartment for diesel storage and a 500 gal compartment for gasoline storage, located at the Plant 1 Fueling Station

T-4701 & T-4702 – two (2) 1,000 gal tanks storing fire traning material with a TVP < 1.5 psia at 20°C, located at the fire training grounds

Meter Proving Activities at the Truck Rack (Denver Terminal)

Note that emissions from the meter proving system are routed to the Truck Rack (Denver Terminal flare) and associated piping from the meter prover to the flare will be managed in accordance with the BWON closed vent system and control device requirements in 40 CFR 61.349 (see Conditions 65.17 thru 65.24).

<u>Units with emissions less than APEN de minimis - non-criteria reportable pollutants (Reg 3 Part C.II.E.3.b)</u>

<u>In-house experimental and analytical laboratory equipment (Reg 3 Part C.II.E.3.i.(i))</u>

Refinery control laboratory

<u>Chemical storage tanks or containers < 500 gal (Reg 3 Part C.II.E.3.n)*</u>

Chemical additive tanks
Bulk chemical storage

<u>Storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications (Reg 3 Part C.II.E.3.fff)*</u>

Tank T330	Diesel
Tank T331	Diesel
Tanks T332	Diesel

One (1) diesel tank, 500 gal capacity, at the Plant 1 Fueling Station

<u>Non-Road Engines</u>

Misc. diesel-driven plant equipment

APPENDIX B

Reporting Requirements and Definitions

with codes ver 8/20/14

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) fails to notify or report as required under the Act; or

(C) falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The permittee must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits.
All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, “malfunction” shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 22. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;

- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]

- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only for emission points subject to CAM)

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

Startup, Shutdown, Malfunctions and Emergencies

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means 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.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

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.

Monitoring and Permit Deviation Report - Part I

1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 22. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 1 (West Plant) and Plant 3 (Asphalt Unit)
OPERATING PERMIT NO: 96OPAD120
REPORTING PERIOD:______________ (see first page of the permit for specific reporting period and dates)

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/ Emergency Condition Reported During Period?	
		YES	NO		YES	NO
D-811	Storage Tank D-811					
D-812	Storage Tank D-812					
D-813	Storage Tank D-813					
D-814	Storage Tank D-814					
T1	Storage Tank T1					
T2	Storage Tank T2					
T3	Storage Tank T3					
T34	Storage Tank T34					
T52	Storage Tank T52					
T55	Storage Tank T55					
T57	Storage Tank T57					
T58	Storage Tank T58					
T59	Storage Tank T59					
T62	Storage Tank T62					
T64	Storage Tank T64					
T65	Storage Tank T65					
T66	Storage Tank T66					
T67	Storage Tank T67					
T68	Storage Tank T68					
T69	Storage Tank T69					
T70	Storage Tank T70					
T71	Storage Tank T71					
T72	Storage Tank T72					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/ Emergency Condition Reported During Period?	
		YES	NO		YES	NO
T74	Storage Tank T74					
T75	Storage Tank T75					
T76	Storage Tank T64					
T77	Storage Tank T77					
T78	Storage Tank T78					
T80	Storage Tank T80					
T81	Storage Tank T81					
T82	Storage Tank T82					
T90	Storage Tank T90					
T91	Storage Tank T91					
T92	Storage Tank T92					
T94	Storage Tank T94					
T96	Storage Tank T96					
T97	Storage Tank T97					
T105	Storage Tank T105					
T112	Storage Tank T112					
T116	Storage Tank T116					
T140	Storage Tank T140					
T142	Storage Tank T142					
T144	Storage Tank T144					
T145	Storage Tank T145					
T146	Storage Tank T146					
T147	Storage Tank T147					
T182	Storage Tank T182					
T191	Storage Tank T191					
T192	Storage Tank T192					
T193	Storage Tank T193					
T194	Storage Tank T194					
T400	Storage Tank T400					
T774	Storage Tank T774					
T775	Storage Tank T775					
T776	Storage Tank T776					
T777	Storage Tank T777					
T778	Storage Tank T778					
T2006	Storage Tank T2006					
T2010	Storage Tank T2010					
T3201	Storage Tank T3201					
T3801	Storage Tank T3801					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/ Emergency Condition Reported During Period?	
		YES	NO		YES	NO
T4501	Storage Tank T4501 (Part of the Plant 1 Wastewater Treatment System – F201)					
T7208	Storage Tank T7208					
	Pipeline Receipt Station Sump					
H-6	Process Heater H6					
H-10	Process Heater H10					
H-11	Process Heater H11					
H-13	Process Heater H13					
H-16	Process Heater H16					
H-17	Process Heater H17					
H-18	Process Heater H18					
H-19	Process Heater H19					
H-20	Process Heater H20					
H-21	Process Heater H21					
H-22	Process Heater H22					
H-27	Process Heater H27					
H-28, 29, 30	Process Heaters H28, H29, and H30					
H-31	Process Heater H31					
H-32	Process Heater H32					
H-33	Process Heater H33					
H-37	Process Heater H37					
H-1716	Process Heater H1716					
H-1717	Process Heater H1717					
H-2101	Process Heater H2101					
H-2401	Process Heater H2401					
H-37	Process Heater H37					
B-4	Steam Boiler B4					
B-6	Steam Boiler B6					
B-8	Steam Boiler B8					
H-25	Sulfur Recovery Units (P101 - SRU #1 & P102 – SRU #2) with Tail Gas Unit (TGU) and TGU Incinerator (H-25)					
P103	FCC Regenerator					
P104	Catalytic Reforming Unit					
R101	Rail Loading Rack and Enclosed VCU					
R102	Truck Loading Rack and Flare					
F203	Truck Loading Rack Drains					
SU0001	Truck Loading Rack Sump					
F1	Main Plant Flare					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/ Emergency Condition Reported During Period?	
		YES	NO		YES	NO
F2	Asphalt Unit Flare					
F3	GBR Unit Flare					
A1	Groundwater Treatment Unit with Air Strippers					
SV1	Soil Vapor Extraction Unit – Engine (non-road engine)					
F201 – uncontrolled sources & sumps	Plant 1 Wastewater Treatment System – uncontrolled sources & sumps (see equipment list in Section I, Condition 5.1)					
F201 – controlled sources	Plant 1 Wastewater Treatment System – controlled sources (see equipment list in Section I, Condition 5.1)					
F101	Asphalt Unit (Plant 3) Wastewater Treatment System					
F102	Asphalt Processing Unit Fugitives					
F103	No. 3 Hydrodesulfurizer Fugitives					
F104	Cryogenic Vapor Recovery Fugitives					
F105	No. 2 Hydrodesulfurizer Fugitives					
F106	Light Straight Run Distillate Fugitives					
F107	Plant wide Fugitive Emissions not subject to Construction Permit Requirements					
F108	Fugitives from Vapor Recovery Unit Debutanizer					
F109	No. 4 Hydrodesulfurizer Fugitives					
F110	Tail Gas Unit Amine Treatment System Fugitives					
F111	Sour Water Stripper System Fugitives					
F112	Modified Tank Farm Piping Fugitives					
F113	Catalytic Reforming Unit Modification Fugitives					
F114	Equipment Leaks Associated with the GBR Unit					
F115	Equipment leaks associated with Bio-Diesel					
F116	Equipment leaks associated with the Relief Valve Project					
F200	Pipeline Receipt Station Fugitives					
F202	Equipment leaks associated with the MPV project					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/ Emergency Condition Reported During Period?	
		YES	NO		YES	NO
F204	Hydrogen (H_2) Plant Individual Drain Systems					
F205	Equipment leaks associated with Plant 1 Rail Rack RSR Compliance Project (replace flare with VCU)					
F206	Equipment leaks associated with the No. 2 HDS Tier 3 ULSG project					
F207	Equipment leaks associated with the fuel gas filter-coalescer for Boiler B-4					
F208	Equipment leaks associated with the P1 Main Plant Flare Isolation Valve Project					
F209	Equipment leaks associated with the RFG Project					
F210	Equipment leaks associated with the Asphalt Unit (Plant 3) Flare RSR Project					
D001	Cold Cleaner Solvent Degreasers					
D004	Industrial Solvent Cleaning Operations					
D002	Emergency Fire Pump Engines					
D003	Emergency Generator (P1 control room)					
P1AC1 & P2AC2	Emergency Air Compressor Engines					
P1EG1	Emergency Generator (pipeline receipt station)					
P1DGTO	Tank Degassing					
MPVs	Miscellaneous Process Vents (defined in 40 CFR Part 63 Subpart CC §63.641), includes maintenance vents.					
Y2	Plant 3 Cooling Tower					
Y1, Y3 & Y4	Plant 1 Cooling Towers					
Pt 606	Recovery Trench AS/SVE System Zone F & G					
Pt 615	Suncor Western Property Boundary AS/SVE System					
Pt 616	M & E East AS/SVE System					
Pt 617	RPC AS/SVE System Zone 2					
Pt 618	Metro Utility Corridor AS/SVE System Zones 1 & 2					
Pt 621	Metro M & E West AS/SVE System Zone 2					
Pt 622	Metro M & E West AS/SVE System Zone 1					

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/ Emergency Condition Reported During Period?	
		YES	NO		YES	NO
Pt 623	Metro South Secondary Area AS/SVE System Zone 1					
Pt 624	Metro South Secondary Area AS/SVE System Zone 2					
Pt 625	Recovery Trench AS/SVE System Zone E & H					
Pt 634	Metro Utility Corridor AS/SVE System Zones 3 & 4					
Pt 635	PCA Subslab Depressurization					
Pt 636	NW Boundary Uncontrolled Zones 3 & 4 (AS System only)					
Pt 637	Laboratory SVE					
Pt 638	East Burlington Ditch AS/SVE					
Pt 639	West of Burlington Ditch AS/SVE					
LO-1	Loading of recovered gasoline/reformate into tank trucks					
D-20	Horizontal above ground 21,150 gallon tanks for storage of recovered gasoline/reformate.					
17675 & 20529	Two (2) 525 gallon tanks for storage of recovered gasoline/reformate.					
	General Conditions					
	Insignificant Activities					

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2]Use the following entries as appropriate:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 1 (West Plant) and Plant 3 (Asphalt Unit)
OPERATING PERMIT NO: 96OPAD120
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency ______ Malfunction______ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction _____ Normal Operation ____________

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _________________ Division Code QA: ______________

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: Acme Corp.
OPERATING PERMIT NO: 96OPZZXXX
REPORTING PERIOD: 1/1/04 - 6/30/06

Is the deviation being claimed as an: Emergency ______ Malfunction __XX____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction
Normal Operation __________________

OPERATING PERMIT UNIT IDENTIFICATION:

Asphalt Plant with a Scrubber for Particulate Control - Unit XXX

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Slurry Line Feed Plugged

Duration

START- 1730 4/10/06
END- 1800 4/10/06

Action Taken to Correct the Problem

Line Blown Out

Measures Taken to Prevent Reoccurrence of the Problem

Replaced Line Filter

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/06 to A. Einstein, APCD

Deviation Code _________________ Division Code QA: ______________

Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 1 (West Plant) and Plant 3 (Asphalt Unit)

FACILITY IDENTIFICATION NUMBER: 0010003

PERMIT NUMBER: 96OPAD120

REPORTING PERIOD:________________ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

____

Printed or Typed Name — Title

____

Signature of Responsible Official — Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

APPENDIX C

Required Format for Annual Compliance Certification Report

ver 8/20/14

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Suncor Energy (U.S.A.), Inc. – Commerce City Refinery, Plant 1 (West Plant) and Plant 3 (Asphalt Unit)

OPERATING PERMIT NO: 96OPAD120
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Operating Permit Unit ID	Unit Description	Deviations Reported[1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
D-811	Storage Tank D-811						
D-812	Storage Tank D-812						
D-813	Storage Tank D-813						
D-814	Storage Tank D-814						
T1	Storage Tank T1						
T2	Storage Tank T2						
T3	Storage Tank T3						
T34	Storage Tank T34						
T52	Storage Tank T52						
T55	Storage Tank T55						
T57	Storage Tank T57						
T58	Storage Tank T58						

Operating Permit Unit ID	Unit Description	Deviations Reported[1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
T59	Storage Tank T59						
T62	Storage Tank T62						
T64	Storage Tank T64						
T65	Storage Tank T65						
T66	Storage Tank T66						
T67	Storage Tank T67						
T68	Storage Tank T68						
T69	Storage Tank T69						
T70	Storage Tank T70						
T71	Storage Tank T71						
T72	Storage Tank T72						
T74	Storage Tank T74						
T75	Storage Tank T75						
T76	Storage Tank T76						
T77	Storage Tank T77						
T78	Storage Tank T78						
T80	Storage Tank T80						
T81	Storage Tank T81						
T82	Storage Tank T82						
T90	Storage Tank T90						
T91	Storage Tank T91						
T92	Storage Tank T92						
T94	Storage Tank T94						
T96	Storage Tank T96						
T97	Storage Tank T97						
T105	Storage Tank T105						
T112	Storage Tank T112						
T116	Storage Tank T116						
T140	Storage Tank T140						
T142	Storage Tank T142						
T144	Storage Tank T144						
T145	Storage Tank T145						
T146	Storage Tank T146						
T147	Storage Tank T147						
T182	Storage Tank T182						
T191	Storage Tank T191						
T192	Storage Tank T192						
T193	Storage Tank T193						
T194	Storage Tank T194						

Operating Permit Unit ID	Unit Description	Deviations Reported[1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
T400	Storage Tank T400						
T774	Storage Tank T774						
T775	Storage Tank T775						
T776	Storage Tank T776						
T777	Storage Tank T777						
T778	Storage Tank T778						
T2006	Storage Tank T2006						
T2010	Storage Tank T2010						
T3201	Storage Tank T3201						
T3801	Storage Tank T3801						
T4501	Storage Tank T4501 (Part of the Plant 1 Wastewater Treatment System – F201)						
T7208	Storage Tanks T7208						
	Pipeline Receipt Station Sump						
H-6	Process Heater H6						
H-10	Process Heater H10						
H-11	Process Heater H11						
H-13	Process Heater H13						
H-16	Process Heater H16						
H-17	Process Heater H17						
H-18	Process Heater H18						
H-19	Process Heater H19						
H-20	Process Heater H20						
H-21	Process Heater H21						
H-22	Process Heater H22						
H-27	Process Heater H27						
H-28, 29, 30	Process Heaters H28, H29, and H30						
H-31	Process Heater H31						
H-32	Process Heater H32						
H-33	Process Heater H33						
H-37	Process Heater H37						
H-1716	Process Heater H1716						
H-1717	Process Heater H1717						
H-2101	Process Heater H2101						
H-2401	Process Heater H2401						
B-4	Steam Boiler B4						
B-6	Steam Boiler B6						
B-8	Steam Boiler B8						

Operating Permit Unit ID	Unit Description	Deviations Reported[1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
H-25	Sulfur Recovery Units (P101- SRU #1 and P102 – SRU #2) with Tail Gas Unit (TGU) and TGU Incinerator (H-25)						
P103	FCC Regenerator						
P104	Catalytic Reforming Unit						
R101	Rail Loading Rack and Flare						
R102	Truck Loading Rack and Enclosed VCU						
F203	Truck Loading Rack Drains						
SU0001	Truck Loading Rack Sump						
F1	Main Plant Flare						
F2	Asphalt Unit Flare						
F3	GBR Unit Flare						
A1	Groundwater Treatment Unit with Air Strippers						
SV1	Soil Vapor Extraction Unit – Engine (non-road engine)						
F201 – uncontrolled sources & sumps	Plant 1 Wastewater Treatment System – uncontrolled sources & sumps (see equipment list in Section I, Condition 5.1)						
F201 – controlled sources	Plant 1 Wastewater Treatment System – controlled sources (see equipment list in Section I, Condition 5.1)						
F101	Asphalt Unit (Plant 3) Wastewater Treatment System						
F102	Asphalt Processing Unit Fugitives						
F103	No. 3 Hydrodesulfurizer Fugitives						
F104	Cryogenic Vapor Recovery Fugitives						
F105	No. 2 Hydrodesulfurizer Fugitives						
F106	Light Straight Run Distillate Fugitives						
F107	Plant wide Fugitive Emissions not Subject to Construction Permit Requirements						
F108	Fugitives from Vapor Recovery Unit Debutanizer						
F109	No. 4 Hydrodesulfurizer Fugitives						
F110	Tail Gas Unit Amine Treatment System Fugitives						
F111	Sour Water Stripper System Fugitives						
F112	Modified Tank Farm Piping Fugitives						

Operating Permit Unit ID	Unit Description	Deviations Reported[1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
F113	Catalytic Reforming Unit Modification Fugitives						
F114	Equipment Leaks Associated with GBR Unit						
F115	Equipment leaks associated with Bio-Diesel						
F116	Equipment leaks associated with the Relief Valve Project						
F200	Pipeline Receipt Station Fugitives						
F202	Equipment leaks associated with the MPV project						
F204	Hydrogen (H_2) Plant Individual Drain Systems						
F205	Equipment leaks associated with Plant 1 Rail Rack RSR Compliance Project (replace flare with VCU)						
F206	Equipment leaks associated with the No. 2 HDS Tier 3 ULSG project						
F207	Equipment leaks associated with the fuel gas filter-coalescer for Boiler B-4						
F208	Equipment leaks associated with the P1 Main Plant Flare Isolation Valve Project						
F209	Equipment leaks associated with the RFG Project						
F210	Equipment leaks associated with the Asphalt Unit (Plant 3) Flare RSR Project						
D001	Cold Cleaner Solvent Degreasers						
D004	Industrial Solvent Cleaning Operations						
D002	Emergency Fire-Pump Engines						
D003	Emergency Generator (P1 control room)						
P1AC1 & P2AC2	Emergency Air Compressor Engines						
P1EG1	Emergency Generator (pipeline receipt station)						
P1DGTO	Tank Degassing						
MPVs	Miscellaneous Process Vents (defined in 40 CFR Part 63 Subpart CC §63.641), includes maintenance vents.						
Y2	Plant 3 Cooling Tower						
Y1, Y3 & Y4	Plant 1 Cooling Towers						

Operating Permit Unit ID	Unit Description	Deviations Reported[1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
Pt 606	Recovery Trench AS/SVE System Zone F & G						
Pt 615	Suncor Western Property Boundary AS/SVE System						
Pt 616	M & E East AS/SVE System						
Pt 617	RPC AS/SVE System Zone 2						
Pt 618	Metro Utility Corridor AS/SVE System Zones 1 & 2						
Pt 621	Metro M & E West AS/SVE System Zone 2						
Pt 622	Metro M & E West AS/SVE System Zone 1						
Pt 623	Metro South Secondary Area AS/SVE System Zone 1						
Pt 624	Metro South Secondary Area AS/SVE System Zone 2						
Pt 625	Recovery Trench AS/SVE System Zone E & H						
Pt 634	Metro Utility Corridor AS/SVE System Zones 3 & 4						
Pt 635	PCA Subslab Depressurization						
Pt 636	NW Boundary Uncontrolled Zones 3 & 4 (AS System only)						
Pt 637	Laboratory SVE						
Pt 638	East Burlington Ditch AS/SVE						
Pt 639	West of Burlington Ditch AS/SVE						
LO-1	Loading of recovered gasoline/reformate into tank trucks						
D-20	Horizontal above ground 21,150 gallon tank for storage of recovered gasoline/reformate.						
17675 & 20529	Two (2) 525 gallon tanks for storage of recovered gasoline/reformate.						
	Insignificant Activities[4]						

[1] If deviations were noted in a previous deviation report , put an “X” under “previous”. If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an “X” under “current”. Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark “no” and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. “Intermittent Compliance” can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance

only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility ____________ is _________ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _______ will be _____ has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in §18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of §25-7 122.1, C.R.S.

____

Printed or Typed Name Title

____

Signature Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

APPENDIX D

Notification Addresses

January 27, 2020 version

1. **Air Pollution Control Division**

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530

ATTN: Title V Permit Unit Supervisor

2. **United States Environmental Protection Agency**

Compliance Notifications:

Enforcement and Compliance Assurance Division
Air and Toxics Enforcement Branch
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Air and Radiation Division
Air Permitting and Monitoring Branch
Mail Code 8ARD-PM
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

APPENDIX E

Permit Acronyms

Listed Alphabetically:

AG-	Acid Gas
AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
AU -	Asphalt Unit
BACT -	Best Available Control Technology
Bbl -	Barrels
BTU -	British Thermal Unit
BWON -	Benzene Waste Operations NESHAP
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CEMS -	Continuous Emission Monitoring Systems
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CMS -	Continuous Monitoring System
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CPMS -	Continuous Parametric Monitoring System
CRS -	Colorado Revised Statute
EF -	Emission Factor
EMD -	Electromotive Diesel
EPA -	Environmental Protection Agency
FCCU -	Fluidized Catalytic Cracking Unit
FI -	Fuel Input Rate in MMBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GMCS -	Gas Migration Control System
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HC -	Hydrocarbon
HHV -	Higher Heating Value
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LDAR -	Leak Detection And Repair
LBS -	Pounds

M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PEMS -	Predictive Emissions Monitoring System
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit
QA/QC -	Quality Assurance/Quality Control
RACT -	Reasonably Available Control Technology
SCC -	Source Classification Code
SCF -	Standard Cubic Feet
SCR-	Selective Catalytic Reduction
SEP -	Supplemental Environment Project
SIC -	Standard Industrial Classification
SNCR -	Selective Non-Catalytic Reduction
SO_2 -	Sulfur Dioxide
SRP -	Sulfur Recovery Plant
SRU -	Sulfur Recovery Unit
TAB -	Total Annual Benzene
TGU -	Tail Gas Unit
TPY -	Tons Per Year
TSP -	Total Suspended Particulate
VOC -	Volatile Organic Compounds

APPENDIX F

Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

APPENDIX G

Consent Decree Benzene, LDAR and Flaring Events

The following terms and conditions are from the Consent Decree in Case No. H-01-4430 as modified by the First Amendment to Consent Decree, entered August 5, 2003 and Second Amendment to the Consent Decree, entered October 2006 by the United States District Court for the Southern District of Texas ("Consent Decree").

Program Enhancements Re: Benzene Waste Operations NESHAP (BWON)

Refinery Compliance Option Changes

Commencing on the Date of Entry of the Consent Decree and continuing through termination, Conoco shall not change the compliance option of any Refinery from the 6 BQ compliance option to the 2 Mg compliance option. If at any time from the Date of Entry of the Consent Decree through its termination, the Denver Refinery is determined to have a TAB equal to or greater than 10 Mg/yr, Conoco shall not utilize the 2 Mg compliance option. Conoco shall consult with EPA and the appropriate state agency before making any change in compliance strategy not expressly prohibited by this Paragraph. All changes must be undertaken in accordance with the regulatory provisions of the Benzene Waste Operations NESHAP. (Paragraph 77)

Carbon Canisters

Except as noted for Conoco's Lake Charles Refinery, Conoco's Refineries requiring control devices shall comply with the requirements of Paragraphs 88 - 96 (either primary and secondary canisters in series or single carbon canisters) at all locations at Conoco's Refineries where a carbon canister(s) is utilized as a control device under the Benzene Waste Operations NESHAP. Lake Charles Refinery may continue to use its primary control system (flare) as the primary control system with single carbon canister system as backup. Lake Charles may change to dual canisters in series if needed. (Paragraph 87)

By no later than seven (7) days after start of operation of each secondary carbon canister, Conoco shall start to monitor for breakthrough between the primary and secondary carbon canisters at times when there is actual flow to the carbon canister, in accordance with the frequency specified in 40 CFR §61.354(d). (Paragraph 91)

Conoco shall replace the original primary carbon canisters with either a fresh carbon canister or the secondary canister immediately when breakthrough is detected. If the original secondary carbon canister is used as the new primary carbon canister, a fresh carbon canister will become the secondary canister. For this Paragraph, "immediately" shall mean within twenty-four (24) hours. (Paragraph 92)

Utilizing single carbon canisters. Conoco shall continue to operate its existing single canisters for short-term operations such as with temporary storage tanks. For all canisters operated as part of a single canister system, "breakthrough" is defined for the purposes of this Decree as any reading of VOC above background. Beginning no later than the Date of Entry of this Consent Decree, Conoco shall monitor for breakthrough from a single carbon canister at times when there is actual flow to the carbon canister, in accordance with the frequency specified in 40 CFR §61.354(d). (Paragraph 93)

For locations where single canisters are utilized, canisters will be replaced when breakthrough is determined within eight (8) hours for canisters with historical replacement intervals of two weeks or less or within twenty-four (24) hours for canisters with a historical replacement interval of more than two weeks. Single carbon canisters can be replaced with a dual system (in series) at any time, provided that Conoco provides notice to EPA and single canister monitoring is continued until the second canister is installed. (Paragraph 94)

Conoco shall maintain a supply of fresh carbon canisters used as single canisters at each Refinery at all times. Conoco shall either maintain the supply or assure a replacement is available within the replacement interval for all canisters used in dual systems. (Paragraph 95)

Records for the requirements of Paragraphs 88 - 95 shall be maintained in accordance with 40 CFR §61.356(j)(10). (Paragraph 96)

Annual Review

Conoco shall establish a process to annually review process and project information for each Refinery, including but not limited to construction projects, to ensure that all new benzene waste streams are included in each Refinery's waste stream inventory during the life of the Consent Decree. Conoco shall have one hundred eighty (180) days from Date of Entry of the Consent Decree to modify existing management of change procedures for this annual review or to develop a new program. (Paragraph 97)

Laboratory Audits

Conoco shall conduct audits of all laboratories that perform analyses of Conoco's benzene waste operations NESHAP samples to ensure that proper analytical and quality assurance/quality control procedures are followed. These audits may be conducted either by Conoco personnel or third parties. (Paragraph 98)

Beginning within six (6) months after the Date of Entry of the Consent Decree, Conoco shall conduct initial audits of the laboratories used by two (2) of its Refineries. Conoco shall complete initial audits of the laboratories used by the remaining Conoco Refineries within twelve (12) months of the Date of Entry of the Consent Decree. In addition, Conoco shall audit any new laboratory used for analyses of benzene samples prior to use of the new laboratory. (Paragraph 99)

During the life of this Consent Decree, ConocoPhillips shall conduct subsequent laboratory audits, such that each laboratory is audited every two (2) years. ConocoPhillips may rely upon audit results obtained by another company that has similar audit requirements if that company has audited the same laboratory within the past twelve (12) months. (Paragraph 100)

Spills

Upon entry of the Consent Decree, Conoco shall review reportable spills within the Refineries identified in Paragraph 5 to determine if benzene waste, as defined under Subpart FF, was generated. For the purposes of this review, 'reportable' will be the smaller of the benzene quantity defined as reportable by either CERCLA or the State in which the particular refinery operates. Conoco shall account for such benzene waste in the respective

TABs as required by 40 CFR §61.342. For the Refineries with a TAB greater than or equal to 10 Mg/year, Conoco will account for such benzene wastes in accordance with the applicable compliance option calculations, as appropriate under Subpart FF, unless the benzene waste is promptly managed in controlled waste management units. (Paragraph 101)

Training

By no later than one hundred twenty (120) days from the Date of Entry of the Consent Decree, Conoco shall develop and begin implementation of annual (i.e., once each calendar year) training for all employees asked to draw benzene waste samples. (Paragraph 102)

Billings, Lake Charles and Ponca City Refineries: For the Billings, Lake Charles and Ponca City Refineries, by no later than one hundred eighty (180) days from the Date of Entry of the Consent Decree, Conoco shall complete the development of standard operating procedures for all control equipment used to comply with the Benzene Waste Operations NESHAP. By no later than two hundred seventy (270) days thereafter, Conoco shall complete an initial training program regarding these procedures for all operators assigned to this equipment. Comparable training shall also be provided to any persons who subsequently become operators, prior to their assumption of this duty. Until termination of this Decree, “refresher” training in these procedures shall be performed at a minimum on a three (3) year cycle. (Paragraph 103)

The Denver Refinery shall comply with the procedure and training provisions of Paragraph 103 if and when that Refinery’s TAB exceeds 10 Mg/yr. Conoco shall propose the schedule for these procedures and training at the same time that Conoco proposes a plan, pursuant to Paragraph 83 that identifies the compliance strategy and schedule that Conoco will implement to come into compliance with the 6 BQ compliance option. (Paragraph 104)

If personnel are employees of contractors, the contractor will provide their employees' training information to Conoco. (Paragraph 105)

Sampling Plans

Conoco shall submit a sampling plan for each Refinery to EPA for approval. The plan will include the information required by Sections L, M and N of this Part. If no Phase Two samples are requested by EPA, the plans shall be submitted no later than December 31, 2002. If EPA requests Phase Two samples, the plan shall be submitted no later than two hundred ten (210) days after EPA’s request. The sampling plan shall be implemented during the first full calendar quarter after Conoco receives written approval from EPA of the sampling plans required by this Paragraph. After two (2) years, Conoco may request an alternative sampling plan for any of its Refineries, including sampling frequency, and EPA should not unreasonably withhold its consent. (Paragraph 106)

End of Line Sampling (6BQ Compliance Option)

Conoco shall submit a sampling plan pursuant to Paragraph 106 to EPA to conduct quarterly “end of the line” benzene determination for the Billings Refinery which is complying with the 6 Mg/yr compliance option (40 CFR §61.342(e)). (Paragraph 108)

Conoco’s plan for the Billings Refinery will contain proposed sampling locations and methods for flow calculations to be used in the quarterly benzene determination. (Paragraph 109)

Conoco’s plan for the Billings Refinery shall also provide for quarterly sampling of all uncontrolled waste streams that count toward the 6 Mg/yr calculation and contain greater than 0.05 Mg/yr of benzene. (Paragraph 110)

Quarterly Estimation of Annual TAB

Conoco shall use all sampling results and approved flow calculation methods under the approved sampling plans (Paragraph 106) to calculate a quarterly and estimate a calendar year value for each refinery. If the quarterly calculation for a refinery made pursuant to this Paragraph exceeds: a) 2.5 Mg for the refinery with TAB historically less than 10 Mg/yr, b) 0.5 Mg for refineries complying with the 2 Mg compliance option, or c) 1.5 Mg for refineries complying with the 6 BQ compliance option, then Conoco shall prepare for that refinery a written summary and schedule of the activities planned to minimize benzene wastes at such facility for the rest of the calendar year to ensure that the calendar year calculation complies with the 10 Mg TAB calculation, or the 2 Mg or 6 BQ compliance options. The summary and schedule are due no later than sixty (60) days after the close of the quarter in which the quarterly calculation exceeded the applicable quantity. (Paragraph 115)

If any estimated calendar year calculation for any facility made pursuant to the preceding Paragraph exceeds: (a) 10 Mg for refineries with TABs historically less than 10 Mg/yr, (b) 2 Mg for refineries complying with the 2 Mg compliance option, or (c) 6 Mg for refineries complying with the 6 BQ compliance option, then Conoco shall prepare for each such refinery a written summary and schedule of the activities planned to minimize benzene wastes at such facility to ensure that the calendar year calculation complies with the Benzene Waste Operations NESHAP compliance option. (The projected annual estimates themselves are not the basis for penalties and are not deemed to be instances of non-compliance for purpose of this Consent Decree.) The summary and schedule are due no later than sixty (60) days after the close of the quarter in which the estimated annual amount exceeded the applicable quantity. (Paragraph 116)

Miscellaneous Measures

The provisions of this Paragraph shall apply to: (a) the Billings, Ponca City and Lake Charles Refineries from the Date of Entry of the Consent Decree through termination of the Consent Decree and (b) to the Denver Refinery, if its TAB exceeds 10 Mg/yr, from such time as a compliance strategy is completed, through termination of the Consent Decree. Conoco shall (Paragraph 117):

> Conduct monthly visual inspections of all water traps used for BWON control within the Refineries’ individual drain systems (Paragraph 117(a));

By no later than June 30, 2002, identify and mark all area drains that are segregated stormwater drains (Paragraph 117(b));

On a quarterly basis, conduct monitoring of the controlled oil-water separators in benzene service in accordance with the “no detectable emissions” provision in 40 CFR §61.347. (Paragraph 117(d))

Conoco shall manage all groundwater remediation conveyance systems at its Billings, Lake Charles and Ponca City Refineries in accordance with the Benzene Waste Operations NESHAP. (Paragraph 118)

Recordkeeping and Reporting Requirements for this Part

In addition to the reports required under 40 CFR §61.357 and the Quarterly Progress Report Procedures of Part XIV (Recordkeeping and Reporting), at the times specified in the applicable provisions and Paragraphs of this Part VIII, Conoco shall make available, as and to the extent required, the reports listed in Paragraph 121 to EPA. (Paragraph 121)

Quarterly Reports: Conoco shall submit the following information quarterly as part of the information submitted in either the quarterly reports required pursuant to 40 CFR §61.357(d)(6) and (7) (“Section 61.357 Reports”), (Billings, Lake Charles, and Ponca City) or in the quarterly reports due pursuant to Part XIV of this Decree (Denver and/or the other three (3) Refineries). This provision is applicable through the Life of the Consent Decree, unless the reporting for (a), (b) or (c) below is modified as provided in Paragraph 123 (Paragraph 122):

Sampling results and approved flow calculations generated pursuant to Sections L, M and N of the Consent Decree. (Paragraph 122(a))

Estimated quarterly and annual TABs calculated and reported pursuant to Section O of the Consent Decree. (Paragraph 122(b))

Initial and/or subsequent training conducted in accordance with Paragraphs 102-105 through the end of calendar quarter for which the quarterly report is due. (Paragraph 122(c))

Initial and subsequent laboratory audits conducted pursuant to Paragraphs 98-100 through the end of calendar quarter for which the quarterly report is due. Conoco shall include, at a minimum, the identification of each laboratory audited, a description of the methods used in the audit, and the results of the audit. (Paragraph 122(d))

Any time after two (2) years of quarterly reporting pursuant to Paragraph 122(a), (b), or (c) of sampling results and estimated calendar calculations, Conoco may submit a request to EPA on any or all of these items to modify the frequency of reporting. This request would include the provision to report for the previous calendar year in the quarterly report due for the last calendar quarter of each year submitted pursuant to the provisions of Part XIV of the Consent Decree. This request for Paragraphs 122(a) and (b) would include a provision to recommence quarterly reporting for any calendar year in which the estimated calendar calculation for any facility indicates it may exceed the annual compliance option. (Paragraph 123)

Conoco shall submit all reports, plans and certifications required to be submitted under this Part to EPA Headquarters. Where indicated, Conoco also shall submit the information to the appropriate state agency. Conoco may submit the materials electronically. Certifications shall be made in accordance with the provisions in Part XIV. (Paragraph 125)

Program Enhancements Re: Leak Detection and Repair

Written Refinery-Wide LDAR Program By not later than one hundred eighty (180) days after the Date of Entry (April 22, 2002) of the Consent Decree, the permittee shall develop and maintain a written program for compliance with all applicable federal and state LDAR regulations. This written program may be specific to each refinery and will include all process units subject to federal and/or state LDAR regulations ("Refinery-wide program"). Until termination of the Decree, the permittee shall implement this program on a Refinery-wide basis, and the permittee shall update the program as necessary to ensure continuing compliance. Each Refinery-wide program shall include the items listed in paragraph 126 of the Consent Decree.

Training By no later than one (1) year from the Date of Entry (April 22, 2002) of the Consent Decree, the permittee shall implement the training program set forth in paragraph 127 of the Consent Decree.

LDAR Audits The permittee shall implement Refinery-wide audits performed as set forth in paragraphs 129 and 130 of the Consent Decree, to ensure the refinery's compliance with all applicable LDAR requirements. The permittee's LDAR audits shall include but not be limited to, comparative monitoring, records review, tagging, data management, and observation of the LDAR technicians' calibrations and monitoring techniques. An audit of the refinery shall occur every two (2) years and, if the permittee-led audits are done, third-party and the permittee-led audits shall be separated by two (2) years. (Paragraph 129)

Actions Necessary to Correct Non-Compliance If the results of any of the audits identify any areas of non-compliance, the permittee shall implement, as soon as practicable, all steps necessary to correct the area(s) of non-compliance, and to prevent, to the extent practicable, a recurrence of the cause of the non-compliance. Until two (2) years after the termination of the Consent Decree, the permittee shall retain the audit reports generated pursuant to paragraphs 129-130 of the Consent Decree and shall maintain a written record of the corrective actions that the permittee takes in response to any deficiencies identified in any audits. In the semi-annual report submitted pursuant to the provisions of Part XIV of the Consent Decree (Recordkeeping and Reporting) for the first calendar quarter of each year, the permittee shall report on the audits and corrective actions for audits performed during the previous year as provided in paragraph 151(b) of the Consent Decree. (Paragraphs 132 and 133)

Internal Leak Definition for Valves and Pumps The permittee shall utilize the following internal leak definitions, unless other permit(s), regulations, or laws require the use of lower leak definitions. (Paragraph 134)

Leak Definition for Valves By no later than two (2) years after Date of Entry (April 22, 2002), the permittee shall utilize an internal leak definition of 500 ppm VOCs for all of its valves in light liquid and/or gas vapor service, excluding pressure relief devices. (Paragraph 135)

Leak Definition for Pumps By no later than two (2) years after the Date of Entry of the Consent Decree, the permittee shall utilize an internal leak definition of 2,000 ppm for its pumps in light liquid and/or gas/vapor service. (Paragraph 136)

Reporting, Recordkeeping, Tracking, Repairing and Re-monitoring Leaks of Valves and Pumps Based on the Internal Leak Definitions

Reporting For regulatory reporting purposes, the permittee may continue to report leak rates in valves and pumps against the applicable regulatory leak definition, or may use the lower, internal leak definitions specified in paragraphs 135 and 136. The permittee will identify in the report which definition is being used. (Paragraph 137)

Recordkeeping, Tracking, Repairing and Re-monitoring Leaks The permittee shall record, track, repair and re-monitor applicable leaks in excess of the internal leak definitions of paragraphs 135 and 136 (at such time as those definitions become applicable), except that the permittee shall have thirty (30) days to make repairs and re-monitor leaks that are greater than the internal leak definitions but less than the applicable regulatory leak definitions. (Paragraph 138)

"First Attempt at Repairs" on Valves The permittee shall implement "first attempt at repair" beginning no later than ninety (90) days after the Date of Entry (April 22, 2002) of the Consent Decree. The permittee shall promptly 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 timing for the "first attempt at repair" of those components which the monitoring personnel are not authorized to repair will be consistent with the existing regulatory requirements. "First attempt at repair" will be made promptly (no later than the next business day) for the valves over 200 ppm that the LDAR monitoring personnel are authorized to attempt repair. The "first attempt at repair" will be re-monitored no later than four business days following the repair at the refinery to assure the leak is not worse. No other action will be required unless the leak exceeds the then-applicable leak definition for the refinery. If, after two (2) years, the permittee can demonstrate with sufficient monitoring data that the "first attempt at repair" at 200 ppm will worsen or not improve the Refinery's leak rates, the permittee may request that EPA reconsider or amend this requirement. (Paragraph 139)

LDAR Monitoring Frequency

Pumps When the lower leak definition for pumps becomes applicable pursuant to paragraph 136, the permittee shall monitor pumps in light liquid service and/or gas vapor service at the lower leak definition on a monthly basis. (Paragraph 140)

Valves Unless more frequent monitoring is required by a State regulation, when the lower internal leak definition for valves becomes applicable pursuant to paragraph 135, the permittee shall implement a program to monitor valves in light liquid and/or gas vapor service – other than difficult to monitor or unsafe to monitor valves – on a quarterly basis, with no ability to skip periods on a process-unit-by-process-unit basis. (Paragraph 141)

Electronic Monitoring, Storing, and Reporting of LDAR Data

Electronic Storing and Reporting of LDAR Data The permittee has and will continue to maintain for the duration of the Consent Decree an electronic database for storing and reporting LDAR data. (Paragraph 142)

Electronic Data Collection During LDAR Monitoring For the duration of the Consent Decree, the permittee shall continue to use dataloggers and/or electronic data collection devices during all LDAR monitoring. The permittee or its designated contractor shall use its/their best efforts to transfer, on a daily basis, electronic data from electronic datalogging devices to the electronic database of Paragraph 142. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp, an operator identification, and an instrument identification. The permittee may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when dataloggers 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 transfer any manually recorded monitoring data to the electronic database of Paragraph 142 within seven (7) days of monitoring. (Paragraph 143)

QA/QC of LDAR Data By no later than one hundred twenty (120) days after the Date of Entry (April 22, 2002) of the Consent Decree, the permittee or a third party contractor retained by the permittee shall develop and implement a procedure to ensure a quality assurance/quality control ("QA/QC") review of all data generated by LDAR monitoring technicians. This QA/QC procedure shall include the procedures as set forth in paragraph 144 of the Consent Decree.

Calibration/Calibration Drift Assessment

Calibration The permittee shall conduct all calibrations of LDAR monitoring equipment using methane as the calibration gas, in accordance with 40 CFR Part 60, EPA Reference Test Method 21. (Paragraph 145)

Calibration Drift Assessment Beginning no later than the Date of Entry (April 22, 2002) of the Consent Decree, 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, an approximately 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. (Paragraph 146)

Delay of Repair Within thirty (30) days of the completion of the written program described in paragraph 126, for any equipment for which the permittee is allowed, under 40 CFR §60.482-9(a) or equivalent state regulations, to place on the "delay of repair" list for repair, the permittee shall implement the provisions of paragraph 147 of the Consent Decree. (Paragraph 147)

For valves: For valves, other than control valves or pressure relief valves, that qualify to be on the "delay of repair" list and are leaking at a rate of 50,000 ppm or greater, the permittee will undertake "extraordinary efforts" to fix the leaking valve rather than keeping 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. For valves, extraordinary efforts for repairs shall be defined as non-routine repair methods. The extraordinary effort will be undertaken within one hundred twenty (120) days of the valve being placed on the "delay of repair" list. After two (2) unsuccessful attempts to repair a leaking valve through extraordinary efforts, the permittee may keep the leaking valve on the "delay of repair" list. The permittee will implement these extraordinary repair procedures within thirty (30) days of completion of the written program. (Paragraph 148)

Within one hundred twenty (120) days of implementation of the written program, the permittee shall also make extraordinary efforts to repair those valves which have been placed on the delay of repair list which leak at 10,000 ppm for more than three (3) years. The permittee may delay these repairs further if it can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner. (Paragraph 149)

Recordkeeping and Reporting Requirements

In addition to the Reports Required under 40 CFR §63.654 and the Semi-Annual Progress Report Procedures of Part XIV (Recordkeeping and Reporting) of the Consent Decree Written Refinery-Wide LDAR Program No later than thirty (30) days after completion of the development of the written refinery-wide LDAR programs that the permittee develops pursuant to paragraph 126, the permittee shall submit a copy of the Refinery's Program to EPA and to the Division. (Paragraph 150)

As Part of Either the Reports Required under 40 CFR §63.654 or the Semi-Annual Progress Report Procedures of Part XIV (Recordkeeping and Reporting) of the Consent Decree Consistent with the requirements of Part XIV of the Consent Decree, the permittee shall include the information set forth in paragraph 151 of the Consent Decree, at the times set forth in paragraph 151, in its semi-annual progress reports.

Agencies to Receive Reports, Plans and Certifications Required in this Part; Number of Copies The permittee shall submit all reports, plans and certifications required to be submitted under Paragraphs 150-151 to EPA. Where indicated, the permittee shall submit the information to the Division. Upon written agreement with parties, the permittee may submit the materials electronically. Certifications shall be made in accordance with Part XIV of the Consent Decree. (Paragraph 153)

Program Enhancements Re: Subpart J and Flaring

Definitions Unless specifically provided in the Consent Decree, terms used in Part X of the Consent Decree shall have the meaning as set forth in paragraph 154 of the Consent Decree.

Future Flaring

By no later than the Date of Entry (April 22, 2002) of the Decree, the permittee shall implement procedures at the refinery for evaluating whether future Acid Gas Flaring Incidents and Tail Gas Incidents are due to Malfunctions. The procedures require Root Cause Failure Analysis and Corrective Action for flaring incidents as specified in the Consent Decree, and stipulated penalties for Acid Gas Flaring Incidents or Tail Gas Incidents if the Root Causes were not due to Malfunctions. (Paragraph 178)

By no later than the Date of Entry of the Decree, the permittee shall implement procedures at the refinery for evaluating whether HC Flaring Incidents are due to Malfunctions, as set forth in paragraph 179 of the Consent Decree. (Paragraph 179)

Tail Gas Incidents and No. 1 Incinerator Incidents

For Tail Gas Incidents, the permittee shall follow the investigative, reporting, and corrective action as outlined in Paragraph 183 and the same assessment of stipulated penalty procedures for Acid Gas Flaring outlined in paragraph 189. Such Tail Gas Incidents would not be counted in the tally of Acid Gas Flaring Incidents under Paragraph 190 of the Consent Decree. (Paragraph 181)

For a No. 1 Incinerator Incident, the permittee will follow the investigative, reporting, and corrective action as outlined in Paragraph 183 and the same assessment of stipulated penalty procedures for Acid Gas Flaring Incidents outlined in paragraph 189 of the Consent Decree. No. 1 Incinerator Incidents shall not be counted in the tally of Acid Gas Flaring Incidents under paragraph 190 of the Consent Decree. (Paragraph 182)

Requirements Related to All Flaring Incidents

Investigation and Reporting No later than forty-five (45) days following the end of an Acid Gas Flaring Incident, Tail Gas Incident, HC Flaring Incident, or a No. 1 Incinerator Incident (individually and collectively referred to as "Flaring Incident"), the permittee shall prepare a report that sets forth the information listed in paragraph 183 of the Consent Decree. The permittee shall submit the report for AG Flaring Incidents, Tail Gas Incidents and No. 1 Incinerator Incidents to the Addresses listed in Paragraph 296 of the Consent Decree. The permittee shall maintain the reports prepared for Hydrocarbon Flaring Incidents on site. The permittee shall summarize the Hydrocarbon Flaring Incidents in the Semi-Annual Progress Reports. (Paragraph 183 and 183a)

Corrective Action

In response to any Acid Gas Flaring Incident, Tail Gas Incident, HC Flaring Incident or No. 1 Incinerator Incident, the permittee, as expeditiously as practicable, shall take 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 the subject incident. (Paragraph 184)

If EPA does not notify the permittee in writing within thirty (30) days of receipt of the report(s) required by paragraph 184 of the Consent Decree that it objects to one or more aspects of the permittee's proposed corrective action(s), if any, and schedule(s) of implementation, if any, then that (those) action(s) and schedule(s) shall be deemed acceptable for purposes of the permittee's compliance with Paragraph 184 above. (Paragraph 185)

EPA does not, however, by its agreement to the entry of the Consent Decree (April 22, 2002) or by its failure to object to any corrective action that the permittee may take in the future, warrant or aver in any manner that any of the permittee's corrective actions in the future will result in compliance with the provisions of the Clean Air Act or its implementing regulations. Notwithstanding EPA's review of any plans, reports, corrective measures or procedures under this Section J, the permittee shall remain solely responsible for compliance with the Clean Air Act and its implementing regulations. (Paragraph 186)

If the EPA does object, in whole or in part, to the permittee's proposed corrective action(s) and/or its schedule(s) of implementation, or, where applicable, to the absence of such proposal(s) and/or schedule(s), it shall notify the permittee of that fact within thirty (30) days following receipt of the report(s) required by Paragraph 183 above. (Paragraph 187)

Nothing in Part XI of the Consent Decree shall be construed as a waiver of EPA's rights under the Clean Air Act and its regulations for future violations of the Clean Air Act or its regulations nor to limit the permittee's right to take such corrective actions as it deems necessary and appropriate immediately following a Flaring or No. 1 Incinerator Incident or in the period during preparation and review of any reports required under Part XI of the Consent Decree. (Paragraph 188)

APPENDIX H

FCCU Regenerator (P103) Compliance Assurance Monitoring Plan

I. Background

a. Emission Unit Description:

Fluid Catalytic Cracking Unit (FCCU) -Regenerator (P103).

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations: Operating Permit Conditions 22.1.1 (underlying Colorado Construction Permit (CP) 09AD0961), 22.9.1 (underlying CP 09AD0961 and Consent Decree No. SA-05-CA-0569, paragraph 95) and 22.11 (NSPS J)

Emission Limitations:
PM 85.4 tons/yr (Condition 22.1.1) – **State-Only Requirement**
PM 1 lb/1,000 lb coke burn (Condition 22.9.1)
PM 1 lb/1,000 lb coke burn (Condition 22.11)

Note that all of the above PM and PM_{10} limitations are for filterable PM only.

Monitoring Requirements: Visible Emissions (Opacity)

c. Control Technology:

The FCCU is equipped with a third-stage separator to control particulate matter emissions.

II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitoring System (COMS).

	Indicator 1
II. Indicator Range	An excursion is defined as any 3-hour period in which the average opacity exceeds 20%, except as provided for below: During periods of startup, shutdown and hot standby, a 3-hour period in which the opacity exceeds 20%, shall not be an excursion provided the provisions in Condition 54.5.5.2 (maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second) are met. Hot standby is defined in Condition 54.5.5.3. Records shall be kept for those periods during startup, shutdown and hot standby when the 3-hour average opacity exceeds 20% but the inlet velocity is at or above 20 feet per second. When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions. Opacity emissions are measured using a COMS located downstream of the third-stage separator (cyclones).
b. QA/QC Practices and Criteria	The existing COMS is certified according to 40 CFR Part 60, Appendix B, Performance Specification 1. The COMS is subject to the QA/QC requirements in 40 CFR Part 60 § 60.13(d) and Appendix F.
c. Monitoring Frequency	Continuous
d. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.
e. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages within an hour will be averaged together. Hourly opacity averages will be used in a 3-hour rolling average.

III. Justification

a. Background:

The pollutant specific emission unit is FCCU regenerator (P103). The catalyst regenerator exhausts through a third-stage separator prior to release to the atmosphere. The third-stage separator is a cyclone designed to remove PM from the regenerator exhaust. In addition to removing PM via the third-stage separator, a slip stream of regenerator exhaust is routed through a fourth-stage separator via a pair of critical flow nozzles. One nozzle is in operation at a time, with the second nozzle acting as a spare. The treated slip stream from the fourth stage is recombined with the regenerator stack upstream of the certified COMS. The combined exhaust flow is subject to the PM emission limits identified in this CAM plan.

b. Rationale for Selection of Performance Indicators:

The source proposed opacity as an indicator and the Division agrees that it is an appropriate indicator of the third-stage separator (cyclone) performance. Based on the relationship between particulate matter and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised cyclone performance.

c. Rationale for Selection of Indicator Ranges:

An excursion from the indicator range is any 3-hour period in which the average opacity exceeds 20%. The source is required to monitor opacity at all times using a COMS, and determine 3-hour opacity averages; however, during periods of startup, shutdown and hot standby, a 3-hour average opacity exceeding 20% is not considered an excursion provided the requirements of Condition 54.5.5.2 (maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second) are met. Hot standby is defined in Condition 54.5.5.3.

The COMS is installed, certified, calibrated, maintained, and operated in accordance with the requirements of 40 CFR §60.11, §60.13, and Part 60, Appendices A and B as required by Condition 59.1.2.2 of the Permit such that the system satisfies the design criteria of §§64.3(a) and (b) under §64.3(d)(2). The only remaining element to determine is the indicator range in accordance with §64.3(d)(3)(ii).

The indicator range is consistent with the continuous compliance demonstration requirements of 40 CFR 63, subpart UUU, "National Emission Standards for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units" (MACT UUU) and was selected for consistency since the No. 1 FCCU is already subject to the MACT UUU requirements. Per §64.4(b) of the CAM rule, "To justify the appropriateness of the monitoring elements proposed, the owner or operator may rely in part on existing applicable requirements that establish the monitoring for the applicable pollutant-specific emissions unit or a similar unit."

MACT UUU includes requirements for limiting metal HAP emissions and includes several compliance options, some of which are based on controlling filterable PM emissions as a surrogate for controlling total metal HAP emissions. The MACT UUU filterable PM limit is 1.0 lb/1,000 lb coke burn-off; the same as the filterable PM limits of 1 lb/1,000 lb coke burn that are included in Conditions 22.9.1 and 22.11.

As a part of the December 1, 2015 Refinery Sector Rule (RSR) revisions to the MACT UUU rule requirements, U.S. EPA provides detailed justification for selecting the monitoring approach, performance indicator, and indicator ranges intended to provide a reasonable assurance of ongoing compliance with a 1.0 lb filterable PM/1,000 lb coke burn emission rate. Therefore, the selection of a CAM monitoring approach that is consistent with the current MACT UUU compliance requirements for the same 1.0 lb filterable PM per 1,000 lb coke burn emission rate meets the indicator range criteria in §64.2(a)(2) because EPA determined that this range assures compliance with this emissions rate.

Specifically, as a part of the recent RSR rule revisions, EPA noted the following regarding the 20% opacity operating limit (see 80 FR 75203, December 1, 2015):

> *Based on the variability of the 3-run average opacity limits, we determined that, if the 3-hour average opacity exceeded 20-percent, then it was highly likely (98 to 99- percent confidence) that the FCCU emissions from the unit tested would exceed the PM emissions limit. After considering the public comments, reviewing the data submitted with those comments, and further review of the compliance study, in this final rule we are adding a 20-percent opacity limit, evaluated on a 3-hour average basis for units subject to NSPS subpart J. As we noted above, a 20-percent opacity limit provides a reasonable correlation with the PM emissions limit, and an exceedance of this 20-percent opacity limit will provide evidence that the PM emissions limit is exceeded.*

MACT UUU provides an alternative option to meeting the 3-hour opacity limit during periods of startup, shutdown and hot standby and that is keeping the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second. EPA noted the following regarding this limit (see 80 FR 75220, December 1, 2015):

> Also, based on the data provided by the commenters, the minimum internal cyclone inlet velocity requirement will provide PM (and therefore metal HAP) emissions reductions during startup and shutdown periods. Therefore, considering the available data, we conclude that MACT for FCCU startup and shutdown events is maintaining the minimum internal cyclone inlet velocity of 20 feet/second.

EPA considered the 20% opacity limit, on a 3-hr rolling average, with the alternative for SSM periods, to be a good indicator of compliance with the PM limit of 1 lb/1,000 coke burn-off limit. "[B]ased on the available data, we have determined that a 20-percent opacity operating limit is well correlated with facilities meeting a limit of 1.0 lb PM/1,000 lbs coke burn-off." [80 Fed. Reg. 75178, 75191 (Dec. 1, 2015)]. Since the PM and PM_{10} emission limits in the permit are based on an emission factor of 1 lb/1,000 lb coke burned, then the 20% opacity indicator assures that the FCCU remains compliance with the PM and PM_{10} limits.

APPENDIX I

Site Remediation MACT (40 CFR Part 63 Subpart GGGGG) Applicability Diagram

APPENDIX J

Plant 1 FCCU Opacity Plan

WEST PLANT FCCU OPACITY COMPLIANCE PLAN

SUNCOR ENERGY (U.S.A.) INC.

COMMERCE CITY REFINERY

VERSION 1.2
8/30/2016

PLANT 1 - #1 FCCU OPACITY MONITORING COMPLIANCE PLAN

TABLE OF CONTENTS

LIST OF ACRONYMS

APCD	Air Pollution Control Division
CAQCC	Colorado Air Quality Control Commission
CDPHE	Colorado Department of Public Health and Environment
CFR	Code of Federal Regulations
COMS	Continuous Opacity Monitoring System
FCCU	Fluidized-bed Catalytic Cracking Unit
Permit	Operating Permit 96OPAD120
Refinery	Commerce City Refinery (both the Plants 1 and 3)
Suncor	Suncor Energy (U.S.A.) Inc.
§	Section

FACILITY DESCRIPTION AND REGULATORY BACKGROUND

Suncor Energy (U.S.A.), Inc., (Suncor) owns and operates the Commerce City Refinery (Refinery) in Commerce City, Colorado. Since Suncor acquired Colorado Refining Company on June 1, 2005, Suncor refers to the portion of the refinery on the west side of Brighton Boulevard, formerly the Conoco refinery, as Plant 1. Plant 1 includes a fluidized-bed catalytic cracking unit (FCCU) equipped with an automated sandblasting system for removing catalyst buildup from the internal surfaces of the FCCU waste heat boiler.

Applicable Regulations

The opacity limits provided in the Permit are based on the general stationary source opacity requirement and the stationary source opacity limits for fire building, cleaning of fire boxes, soot blowing, start-up, process modification or adjustment of control equipment in the Colorado Air Quality Control Commission's (CAQCC) Regulation No. 1, Section (§) II.A.1 and Regulation No. 1, §II.A.4, respectively. As provided for in the Colorado Department of Public Health and Environment Air Pollution Control Division (APCD) Operating Permit Number 96OPAD120 (Permit) issued for the refinery, removal of catalyst buildup from the internal surfaces of the FCCU waste heat boiler is considered to be soot blowing for opacity limit purposes (as noted in Condition 35.6.2).

The Permit includes a requirement to prepare and submit a monitoring plan to be used for determining when the 30 percent opacity limit in Condition 35.2 applies and how compliance will be monitored. This Opacity Compliance Monitoring Plan is intended to satisfy the Monitoring provisions of Permit Condition 35. This opacity monitoring plan applies only to the Plant 1 FCCU.

The FCCU is also subject to the opacity limits in 40 CFR 60 Subpart J §60.102(a)(2) and 40 CFR 63 Subpart UUU §63.1564(a)(1) and (a)(2).

Opacity Compliance Plan Organization

This Opacity Compliance Monitoring Plan specifies how compliance with the previously described requirements will be monitored. Section 2.0 identifies how opacity will be monitored. Section 3.0 describes how periods of sandblasting will be identified. Section 4.0 describes when and how the 30 percent opacity threshold will be applied. Section 5.0 describes record keeping and reporting procedures.

OPACITY MEASUREMENTS

The FCCU is equipped with a continuous opacity monitoring system (COMS) for determining the opacity of the FCCU exhaust gases. The instantaneous (1-second interval) monitoring data from the COMS is recorded by the plant's environmental data management system (E!CEMS). These data are used to generate 1-minute block averages. The block averages start at the beginning of a minute and are sequential, not rolling, averages. E!CEMS is used to store the block averages.

The COMS is installed, certified, calibrated, maintained, and operated in accordance with the requirements of 40 CFR §60.11, §60.13, and Part 60 Appendices A and B as required by Condition 59.1.1.4 of the Permit.

SANDBLAST EVENT MONITORING

The internal surfaces of the FCCU waste heat boiler (X-184) are periodically cleaned by introducing sand into the exhaust gases upstream of the waste heat boiler. This sand removes catalyst buildup, potentially leading to a period of increased opacity (defined as opacity in excess of the Regulation No. 1, §II.A.1 limit of 20 percent). This sandblasting is controlled through an automated sandblasting system. E!CEMS is used to monitor and record the signal from the automated sandblast system indicating when sand is being introduced into the system.

In the event that the automated sandblast system is not used and sand is added manually, operator logs will be used and reviewed to determine when a sandblasting event was initiated.

The introduction of the sand into the system by the automated system is done rapidly with a single shot. There is greater variability in the duration and magnitude of the shot if performed manually. Neither the automated signal nor the operator logs track the duration of the sandblast event itself. The sandblast event is assumed to be complete when opacity readings drop to and remain at pre-sandblast levels, or after 6 minutes, whichever is less.

COMPLIANCE DEMONSTRATIONS

Regulation 1, §II.A.1 - 20 Percent Limit

For purposes of demonstrating compliance with the CAQCC Regulation No. 1 §II.A.1 20 percent limit on opacity, 6-minute average opacity readings will be calculated from 24 consecutive 15-second averages. The 6-minute periods will begin at the start of the hour, with a total of 10 averages generated during the hour. Averages will be block, not rolling. The COMS output will be recorded in E!CEMS. The 20 percent limit will apply during all periods however, based on APCD comments; any individual minute affected by a sandblast will be removed from the calculation of the 6-minute block average. This will result in 6-minute blocks of time that are comprised of less than 6 valid 1-minute readings.

Any six minute period not affected by a sandblast, with an observed opacity reading (unaffected by sandblast) in excess of 20 percent will be identified as not being in compliance with CAQCC Regulation No. 1 §II.A.1 (Condition 35.1 of the Permit).

In the event that all or a portion of a sandblast event occurs during a 6-minute period, the CAQCC Regulation No. 1 §II.A.4 30 percent limit on opacity described in Section 4.2 applies as well.

Regulation 1, §II.A.4 - 30 Percent Limit

For purposes of demonstrating compliance with the CAQCC Regulation No. 1 §II.A.4 30 percent limit on opacity, 1-minute average opacity readings will be calculated from 4 consecutive 15-second averages. The COMS output will be recorded in E!CEMS.

The beginning of the sandblast events will be identified from the signal generated by the automated sandblast system, or from operator logs. The sandblast event will be assumed to last for the lesser of the time required for 1 minute opacity readings to fall below 20 percent, or six minutes as described in Section 3.0 of this plan.

The 6-minute averaging period starts with each new minute (i.e. there are sixty 6-minute blocks beginning each hour, with five 1-minute averages common to the adjoining blocks). All six 1-minute averages within the averaging period are included when calculating the 6-minute average opacity, regardless of whether or not that individual minute was affected by a sandblast. Each 6-minute block average that includes a sandblast event will be compared to the 30 percent opacity threshold. If the 6-minute rolling average exceeds 30 percent during a sandblast, the source will be identified as not being in compliance with CAQCC Regulation No. 1 §II.A.4 (Condition 35.2 of the Operating Permit). However if any given block of 1-minute observations results in the exceedance of the 30 percent threshold for more than 6 minutes, it will only be reported as a single event, not as each individual exceedance of the 30 percent threshold. This results in an event-based reporting process.

NSPS J and MACT UUU - 30 Percent Limit

For purposes of demonstrating compliance with the 40 CFR 60 Subpart J §60.102(a)(2) and 40 CFR 63 Subpart UUU §63.1564(a)(1) - 30 percent limit on opacity, 6-minute block average opacity readings will be calculated from 24 consecutive 15-second averages. The 6-minute periods will begin at the start of the hour, with a total of 10 averages generated during the hour. Averages will be block, not rolling. The COMS output will be recorded in E!CEMS. The 30 percent limit will apply during all periods, except for one 6-minute average opacity reading in any one hour period per § 63.1564(a)(1).

MACT UUU – 20 Percent Limit

For purposes of demonstrating compliance with the 40 CFR 63 Subpart UUU § 63.1564(a)(2) 20 percent limit on opacity, 3-hour rolling averages will be calculated. Three 1-hour block averages will be used to calculate the 3-hour rolling average opacity. The COMS output will be recorded in E!CEMS. The 20 percent limit will apply during all periods, except during periods of startup, shutdown and hot standby if the source elects to comply with the alternate limit contained in § 63.1564(a)(5)(ii).

RECORDKEEPING AND REPORTING PROCEDURES

The purpose of this section is to describe recordkeeping and reporting procedures for the FCCU opacity observations described in this document.

As outlined in Operating Permit Section IV (General Conditions), Condition **Error! Reference source not found.**, records of the calculations described in this document will be kept on-site for 5 years.

E!CEMS will be used to store 1-second readings, 1-minute averages, 6-minute block and rolling averages and 3-hour rolling averages.

APPENDIX K

Prevention of Significant Deterioration (PSD) Review and Non-Attainment Area New Source Review (NASR) Applicability Tests

An owner or operator of a major stationary source must determine whether a project will trigger major stationary source permitting requirements (i.e., PSD and/or NANSR) by conducting an applicability test using the procedures in Colorado Regulation No. 3, Part D, Section I.B. Sources that conduct the actual-to-projected actual test for a project that requires a minor permit modification in accordance with Section X. of Part C, requires a significant permit modification in accordance with Section I.A.3. of Part C, a modification as defined in Section I.B.28. of Part A or that requires a minor source permit under Part B are required to submit the information in Colorado Regulation No. 3, Part D, Section I.B.4.a through d and that information shall be included in an appendix of the Title V Operating permit or as a permit note in the construction permit (see Colorado Regulation No. 3, Part D, Section I.B.4)

An owner or operation is also required to monitor emissions of any NSR regulated pollutant that could increase as a result of the project for a period of five years or ten years (if the project increases the design capacity or the potential to emit) following resumption of regulation operations after the project is completed and to submit reports, if applicable, as required by Colorado Regulation No. 3, Part D, Section V.A.7.c and d and Section VI.B.5 and 6 (see Section IV, Condition 24If actual emissions from the sources affected by the project exceed baseline emissions by a significant amount and are different from projected actual emissions presented in this Appendix within the five or ten year period following completion of the project, the project may need to be re-evaluated to determine whether the project resulted in a significant emissions increase or a significant net emissions increase at a major stationary source.

This Appendix K includes the PSD and/or NANSR applicability tests submitted for the equipment addressed in this permit.

<u>Miscellaneous Process Vent (MPV) Project</u>

The purpose of the MPV Project is to address the new equipment necessary to meet the requirements for MPVs in the December 1, 2015 Refinery Sector Rule (RSR) Revision. The RSR revisions primarily address the two refinery NESHAPs, 40 CFR Part 63 Subparts CC and UUU. The December 1, 2015 RSR revisions removed “episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring and catalyst transfer operations” from the exception to the definition of miscellaneous process vent, making this equipment newly subject to the requirements in 40 CFR Part 63 Subpart CC.

In order to comply with the new MPV requirements, the source is proposing to install new connections to the flare header systems. The new flare connection systems will consist of permanent, direct equipment connections as well as purge manifolds for as needed, temporary connections. The installation of purge manifolds and other flare header connections will allow the source to prepare equipment for maintenance by purging with steam and/or nitrogen to the flare and will result in routing materials to the flares that were previously routed directly to the atmosphere.

This project does not increase the design capacity or potential to emit, therefore, the timeframe to monitor emissions from this project is five years after resuming operation upon completion of the project. The MPV project was completed in September 2017.

The applicability analysis related to the MPV modification is included in this appendix. The MPV modification also affected equipment located at Plant 2 of the refinery which is addressed in a separate Title V permit (95OPAD108) but is included here to show the complete analysis. Note that except for the Plant 1 Main Flare (F1), the source has taken permit limits at the projected actual emission (PAE) level. In addition, permit limits were included in both Title V permits for new piping components. Finally, only the incremental emission increases from the boiler have been included in the analysis. Any increased utilization from the boilers (necessary for the steam tracing on the purge manifolds to prevent freezing) is expected to be minimal, if any.

Except for the new piping components, the units affected by this modification are existing units. Therefore, the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE).

Specific details regarding how BAE and PAE were determined can be found in the technical review document prepared for the February 22, 2018 revised Title V permit.

The resulting emissions increases for the project are shown below:

Table 1: Actual Emission Increases

	Emissions (tons/yr)				
	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
P1 Flare					
Baseline	39.12	8.58	83.29	0.94	36.42
PAE	96.52	21.17	205.50	2.32	167.52
Capable of Accommodating	96.36	21.14	205.15	2.32	165.84
Excludable[1]	57.24	12.56	121.86	1.38	129.42
Adjusted PAE[2]	39.28	8.61	83.64	0.94	38.10
Change in Emissions[3]	**0.16**	**0.03**	**0.35**	**4.00E-03**	**1.68**
P3 (AU) Flare					
Baseline	2.42	0.53	5.16	5.82E-02	1.20E-02
PAE	5.43	1.19	11.56	0.13	16.86
Capable of Accommodating	2.42	0.53	5.16	5.83E-02	1.20E-02
Excludable[1]	0.00E+00	0.00E+00	0.00E+00	1.00E-04	0.00E+00
Adjusted PAE[2]	5.43	1.19	11.56	0.13	16.86
Change in Emissions[3]	**3.01**	**0.66**	**6.40**	**7.17E-02**	**16.85**
GBR Flare					
Baseline	5.06	1.28	11.61	0.14	1.18E-02
PAE	11.09	2.85	25.92	0.31	0.21
Capable of Accommodating	3.55	0.91	8.29	0.10	0.19

	Emissions (tons/yr)				
	CO	NO_X	VOC	PM/PM_{10}/ $PM_{2.5}$	SO_2
Excludable[1, 4]	0.00	0.00	0.00	0.00	0.18
Adjusted PAE[2]	11.09	2.85	25.92	0.31	0.03
Change in Emissions[3]	**6.03**	**1.57**	**14.31**	**0.17**	**0.02**
P2 Flare					
Project Emissions[5, 6]	**0.65**	**0.14**	**0.73**	**0.02**	**13.62**
P1/3 Boilers	0.14	0.31	0.01	0.02	0.07
P2 Boilers	0.15	0.11	0.02	0.04	0.04
P1/3 Fugitive VOCs from New Piping Components			3.71		
P2Fugitive VOCs from New Piping Components			2.55		
Total	**10.14**	**2.82**	**28.08**	**0.32**	**32.28**

[1]Excludable emissions equals capable of accommodating minus baseline emissions.
[2]Adjusted PAE equals PAE minus excludable emissions.
[3]Change in emissions is adjusted PAE minus baseline.
[4]If capable of accommodating emissions are less than or equal to baseline emissions, excludable emissions are zero.
[5]As indicated in Table 2 below, the change in CO, PM, PM_{10}, $PM_{2.5}$, NO_X and VOC emissions for the P2 flare are all negative due to the request to reduce the throughput limit for the flare. In part 1 of the PSD/NANSR applicability analysis (assess project emissions), only increases are included. So if the applicability test (i.e. PAE minus BAE) were negative the emissions increase would be zero for part 1 of the analysis. In order to appropriately assess project emissions, the increase from the P2 flare is the emissions estimated for the project alone (see the technical review document prepared for the February 22, 2018 renewal Title V permit, page 27). In accordance with Regulation No. 3, Part D, Section II.A.38.b.(iii), emissions related to the project cannot be excluded.
[6]SO_2 emissions are based on the applicability test shown in Table 2 below.

Table 2: Plant 2 Change in Actual Emissions

	P2 Flare Emissions (tons/yr)				
	CO	NO_X	VOC	PM/PM_{10}/ $PM_{2.5}$	SO_2
Baseline	50.52	11.08	56.55	1.22	4.59
PAE	66.97	14.69	74.97	1.61	18.21
Capable of Accommodating	75.71	16.61	84.75	1.82	4.59
Excludable[1,]	25.19	5.53	28.20	0.60	0.00
Adjusted PAE[2]	41.78	9.16	46.77	1.01	18.21
Change in Emissions[2,]	**-8.74**	**-1.92**	**-9.78**	**-0.21**	**13.62**

[1]Excludable emissions equals capable of accommodating minus baseline emissions.
[2]Adjusted PAE equals PAE minus excludable emissions.
[3]Change in emissions is adjusted PAE minus baseline.

Plant 1 Main Plant Flare Refinery Sector Rule (RSR) Project

The purpose of project is to upgrade the Plant 1 flare in order to comply with the flare requirements in the December 1, 2015 RSR revisions. The new flare requirements in MACT CC are essentially an enhancement of the requirements in 40 CFR Part 63 Subpart A § 63.11(b) (operate with a flame present at all times, no visible emissions and exit velocity and flare gas Btu content requirements) by requiring monitoring to ensure the flares are properly operated to achieve the 98 percent reduction efficiency that was expected for flares used to comply with MACT CC requirements.

The December 1, 2015 MACT CC flare revisions primarily require additional monitoring requirements, thus there is no expectation that additional waste gases will be combusted by flares or that the operation of any of the refinery process units will be changed as a result of this project. However, under the MACT CC requirements, sources are required to maintain the net heating value of the flare combustion zone gas at or above 270 Btu/scf, determined on a 15-minute block period, when regulated material is routed to the flare on for at least 15 minutes. Suncor anticipates that supplemental gas will be necessary to ensure that the flare can comply with the combustion zone gas heat content requirements, which will result in an increase in flare emissions. As part of the project, new piping components (i.e. flanges, valves, etc.) will be installed and result in a slight emissions increase.

This project does not increase the design capacity or potential to emit, therefore, the timeframe to monitor emissions from this project is five years after resuming operation upon completion of the project. The Plant 1 flare RSR project was scheduled to begin construction in July 2018, with completion by January 30, 2019.

Except for the new piping components the only other emission unit unit affected by this modification is the Plant 1 flare (an existing unit). Therefore, the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE).

Specific details regarding how BAE and PAE were determined can be found in the technical review document prepared for the **July 9, 2024** renewal Title V permit.

The resulting emissions increases for the project are shown below

	Emissions (tons/yr)				
	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$	SO_2
Plant 1 Main Plant Flare					
Baseline	39.12	8.58	32.16	0.94	36.42
PAE	102.05	22.38	80.03	2.45	167.55
Capable of Accommodating	96.36	21.14	79.20	2.32	165.84
Excludable[1,]	57.24	12.55	47.04	1.38	129.42
Adjusted PAE[2]	44.81	9.83	32.99	1.07	38.13
Change in Emissions[2,]	**5.69**	**1.25**	**0.83**	**0.13**	**1.71**
Fugitive VOCs from New Piping Components[4]			**0.47**		

	Emissions (tons/yr)				
	CO	NO_X	VOC	PM/PM_{10}/ $PM_{2.5}$	SO_2
Total Emissions Increase	**5.69**	**1.25**	**1.30**	**0.13**	**1.71**
PSD/NANSR Significance Level (T5 Minor Mod Level)[5]	100	40	40	25/15/10	40

[1]Excludable emissions equals capable of accommodating minus baseline emissions.

[2]Adjusted PAE equals PAE minus excludable emissions.

[3]Change in emissions is adjusted PAE minus baseline.

[4]New Equipment.

[5]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X. Note that the area was classified as severe nonattainment for ozone on November 7, 2022.

No. 2 HDS Tier 3 Ultra Low Sulfur Gasoline (ULSG) Project

The pupose of project is to meet the Tier 3 ULSG requirements. On April 28, 2014 EPA finalized Tier 3 motor vehicle emission and fuel standards. Under the provisions of the rule, refineries are required to reduce sulfur in gasoline to 10 ppm, on an annual average and no more than 80 ppm sulfur, on a per-gallon basis. The Tier 3 standards took effect on January 1, 2017, although small refiners and small volume refineries did not have to comply until January 1, 2020.

In order to meet these requirements, the sources will complete upgrades to the No 2 HDS to increase the unit's capacity from 12,000 to 15,000 barrels per day (bpd). The initial application (received November 5, 2018) also indicated that there would additional changes to meet the Tier 3 ULGS standards, specifically replacing the existing variable frequency drive (VFD) on the C-1715 Recycle Gas Compressor in the No. 4 HDS and implementing the use of gasoline sulfur reducing (GSR) additive at one or both of the FCCUs but emission increases from these projects were not addressed. Due to requests from the Division, the source indicated that replacement of the VFD would not result in an increase in emissions (like-kind replacement) and addressed the use of GSR additives in the P1 and P2 FCCUs although they indicated that GSR additives were not expected to be using the P1 FCCU.

This project increases the design capacity of the No. 2 HDS, therefore, the timeframe to monitor emissions from this project is ten years after resuming operation upon completion of the project. The No. 2 HDS ULSG Project was completed in November 2019.

Except for the new piping components, the units affected by this modification are existing units. Therefore, the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE). Emission limits were included in the permit for new piping components. Only incremental emission increases from the boilers and the Plant 2 SRU are included in the analysis.

Specific details regarding how BAE and PAE were determined can be found in the technical review document prepared for the **July 9, 2024** renewal Title V permit.

The resulting emissions increases for the project are shown below:

	Emissions (tons/yr)						
Emission Unit	CO	NOx	SO_2	VOC	PM	PM_{10}	$PM_{2.5}$
No. 2 HDS Heater (H-10)[1]							
Baseline	8.22	9.78	0.11	0.54	0.74	0.74	0.74
Projected Actual Emissions (PAE)	12.06	14.35	3.86	0.79	1.09	1.09	1.09
Capable of Accommodating	10.65	12.68	0.25	0.70	0.96	0.96	0.96
Excludable[2]	2.43	2.89	0.13	0.16	0.22	0.22	0.22
Adjusted PAE[3]	9.62	11.46	3.73	0.63	0.87	0.87	0.87
Emissions Increase[4]	**1.41**	**1.67**	**3.62**	**0.09**	**0.13**	**0.13**	**0.13**
No. 2 HDS Heater (H-19)[1]							
Baseline	3.51	5.12	0.05	0.23	0.32	0.32	0.32

Emission Unit	Emissions (tons/yr)						
	CO	NOx	SO_2	VOC	PM	PM_{10}	$PM_{2.5}$
PAE	5.15	7.50	1.84	0.34	0.47	0.47	0.47
Capable of Accommodating	4.28	6.24	0.09	0.28	0.39	0.39	0.39
Excludable[2]	0.77	1.13	0.04	0.05	0.07	0.07	0.07
Adjusted PAE[3]	4.38	6.38	1.80	0.29	0.40	0.40	0.40
Emissions Increase[4]	**0.87**	**1.26**	**1.75**	**0.06**	**0.08**	**0.08**	**0.08**
P1 SRUs, Tail Gas Unit (TGU) & TGU Incinerator (H-25)[1]							
Baseline	0.89	0.67	26.82	0.12	0.17	0.17	0.17
PAE	1.10	0.83	35.71	0.15	0.21	0.21	0.21
Capable of Accommodating	1.10	0.83	35.67	0.15	0.21	0.21	0.21
Excludable[2]	0.21	0.16	8.85	0.03	0.04	0.04	0.04
Adjusted PAE[3]	0.89	0.67	26.86	0.12	0.17	0.17	0.17
Emissions Increase[4]	**0.00**	**0.00**	**0.04**	**0.00**	**0.00**	**0.00**	**0.00**
P1 Boilers (B-4, B-6 and B-8)	**0.18**	**0.57**	**0.09**	**0.02**	**0.02**	**0.02**	**0.02**
P2 SRU	**--**	**--**	**0.84**	**--**	**--**	**--**	**--**
Fugitive VOCs from new components[5]	**--**	**--**	**--**	**1.14**	**--**	**--**	**--**
Total Emissions Increase (tpy)	**2.45**	**3.51**	**6.33**	**1.31**	**0.23**	**0.23**	**0.23**
PSD/NANSR Significance Level (T5 Minor Mod Level)[6]	100	40	40	40	25	15	10

[1]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the projected increase in emissions due to increased utilization of equipment.

[2]Exludable emissions equal capable of accommodating minus baseline emissions

[3]Adjusted PAE is PAE minus excludable emissions

[4]Change in emissions (emissions increase) is adjusted PAE minus baseline or if PAE not adjusted, PAE minus baseline.

[5]New Equipment.

[6]Indicates the NANSR significance level on the date the complete minor modification application was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was classified as a serious ozone non-attainment area on January 27, 2020 and for minor modification applications submitted on and after that date, the significance level drops to 25 tons/yr of VOC or NO_X. Note that the area was classified as severe nonattainment for ozone on November 7, 2022.

H-33, H-37 Stack Replacement Project

The purpose of this modification is to replace the stacks on two of the No. 3 Crude Unit (CU) heaters, H-33 and H-37 in order to address draft issues with both of the heaters that cause safety problems, flame instability during high or shifting winds, inaccurate oxygen readings and reduced efficiency. In addition, the existing burners on H-37 will be replaced with ultra-low NO_X burners (ULNB). The application indicates that the design heat input rate for H-37 will not change as a result of the ULNB installation. The application indicates that with this project, the No. 3 CU design rate will increase to the safe operating level of 38,540 barrels per day (bpd), note that the previous operating level of this unit was presumed to be 37,700 bpd. The incremental increase in the processing rate of the No. 3 CU is 2,798 bpd. This is based on the projected (38,540 bpd) minus baseline (35,742 bpd) processing rate.

This project increases the design capacity of the No. 3 CU, therefore, the timeframe to monitor emissions from this project is ten years after resuming operation upon completion of the project. The H-33, H-37 Stack Replacement Project is anticipated to be completed during the 2021 Turnaround (April 2021).

Except for the new piping components, the units affected by this modification are existing units. Therefore, the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE). Emissions from new piping components were below the APEN de minimis level, therefore, a permit is not required for these components. The source did request that the NO_X emission limit for H-37 be revised to reflect the ULNB.

Specific details regarding how BAE and PAE were determined can be found in the technical review document prepared for the **July 9, 2024** renewal Title V permit.

The resulting emissions increases for the project are shown below:

Emission Unit/ Value	H-33, H-37 Stack Replacement Emissions (tons/yr)						
	CO	NOx	SO_2	VOC	PM (f)[1]	PM_{10} (t)[2]	$PM_{2.5}$ (t)[2]
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
No.1 FCCU							
Baseline	4.67	50.82	25.39	25.74	55.52	76.34	74.71
PAE	12.34	60.03	33.51	28.65	62.86	86.43	84.59
Capable of Accommodating	12.33	59.95	33.47	28.61	62.77	86.31	84.47
Excludable[3]	7.66	9.13	8.07	2.87	7.25	9.97	9.76
Adjusted PAE[4]	4.69	50.90	25.44	25.78	55.60	76.46	74.83
Emissions Increase[5]	**0.02**	**0.08**	**0.05**	**0.04**	**0.08**	**0.12**	**0.11**
No. 2 FCCU							
Baseline	3.37	26.78	12.36	9.53	19.14	26.32	25.76
PAE	9.25	33.41	19.79	11.33	23.16	31.85	31.17
Capable of Accommodating	9.06	32.73	19.39	11.10	22.69	31.20	30.54
Excludable[3]	5.69	5.96	7.03	1.57	3.55	4.88	4.78
Adjusted PAE[4]	3.56	27.46	12.76	9.76	19.61	26.97	26.39
Emissions Increase[5]	**0.19**	**0.68**	**0.40**	**0.23**	**0.47**	**0.65**	**0.63**
No. 1 and No. 2 SRU							
Baseline	0.93	0.69	17.02	0.12	0.17	0.17	0.17

Emission Unit/ Value	H-33, H-37 Stack Replacement Emissions (tons/yr)						
	CO	NOx	SO_2	VOC	PM (f)[1]	PM_{10} (t)[2]	$PM_{2.5}$ (t)[2]
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
PAE	0.99	0.74	18.38	0.13	0.18	0.18	0.18
Emissions Increase[6]	**0.07**	**0.05**	**1.36**	**0.01**	**0.01**	**0.01**	**0.01**
N0. 3 SRU							
Baseline	0.51	0.60	40.34	0.03	0.05	0.05	0.05
PAE	0.51	0.61	44.71	0.03	0.05	0.05	0.05
Emissions Increase[6]	**0.01**	**0.01**	**4.37**	**0.00**	**0.00**	**0.00**	**0.00**
Heaters[7]							
Baseline[8]	169.21	202.97	6.14	13.39	19.40	19.50	19.00
PAE[8]	175.75	212.54 [200.36]	6.54	14.06	20.33	20.33	20.33
Emissions Increase[6, 7, 8]	**6.54**	**9.57 [8.03]**	**0.41**	**0.67**	**0.93**	**0.93**	**0.93**
Tanks[9]							
Baseline	--	--	--	10.66	--	--	--
PAE	--	--	--	15.06	--	--	--
Emissions Increase	**--**	**--**	**--**	**4.39**	**--**	**--**	**--**
No. 1 Cat Poly							
Baseline	--	--	--	--	1.17	1.17	1.17
PAE	--	--	--	--	1.18	1.18	1.18
Emissions Increase[6]	**--**	**--**	**--**	**--**	**0.01**	**0.01**	**0.01**
No. 2 Cat Poly							
Baseline	--	--	--	--	1.86	1.86	1.86
PAE	--	--	--	--	1.87	1.87	1.87
Emissions Increase[6]	**--**	**--**	**--**	**--**	**0.01**	**0.01**	**0.01**
WWTP							
Baseline	--	--	--	5.03	--	--	--
PAE	--	--	--	5.38	--	--	--
Emissions Increase[6]	**--**	**--**	**--**	**0.35**	**--**	**--**	**--**
New Fugitive Emissions							
Emissions Increase	**--**	**--**	**--**	**0.29**	**--**	**--**	**--**
Plant 1 Truck Loading Rack							
Emissions Increase	**0.65**	**0.14**	**0.00**	**0.74**	**0.00**	**0.00**	**0.00**
Total Project Emissions Increase	**7.47**	**10.53 [8.99]**	**6.59**	**6.73**	**1.52**	**1.73**	**1.71**
PSD/NANSR Significance Level (T5 Minor Mod Level)[10]	100	25	40	25	25	15	10

[1]Condensable PM is not included for purposes of PSD/NANSR applicability for the FCCU (not required, see footnote 2). PM emissions from fuel burning equipment includes condensable PM.

[2]Includes filterable plus condensable particulate matter. Per Reg 3, Part D, Section II.A.40.g condensable PM is included in PM_{10} and $PM_{2.5}$ for purposes of PSD/NANSR applicability.

[3]Excludable emissions equals capable of accommodating minus baseline

[4]Adjusted PAE equals PAE minus excludable emissions.

[5]Change in emissions is adjusted PAE minus baseline.

Emission Unit/ Value	**H-33, H-37 Stack Replacement Emissions (tons/yr)**						
	CO	**NOx**	**SO_2**	**VOC**	**PM (f)[1]**	**PM_{10} (t)[2]**	**$PM_{2.5}$ (t)[2]**
	tpy	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**

[6]Change in emissions is PAE minus baseline.

[7]Values shown include PAE for H-37 as if ULNB were not installed. Values in brackets "[ ]" show emissions with ULNB installed on H-37.

[8]A detailed summary of BAE, PAE and the change in emissions for the heaters is included below.

[9]Affected tanks are T-67, T-72, T-144, T-775, T-776, T-777 and T-2010.

[10]Indicates the NANSR significance level for a serious ozone nonattainment area. The area was classified as a serious ozone nonattainment area on January 27, 2020. Note that the area was classified as severe nonattainment for ozone on November 7, 2022.

Heater Summary

Details on BAE, PAE and the change in emissions associated with the heaters are shown in the tables below.

Combined Heater Baseline Emissions

Heater	**NOx**	**CO**	**VOC**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
H-13	2.10	1.77	0.12	0.16	0.16	0.16	0.04
H-33	1.15	1.85	0.12	0.17	0.17	0.17	0.04
H-17	17.22	14.41	0.95	1.31	1.31	1.31	0.33
H-37	19.59	16.39	1.08	1.49	1.49	1.49	0.38
H-6	1.12	1.88	0.12	0.17	0.17	0.17	0.04
H-11	13.67	11.48	0.75	1.04	1.04	1.04	0.22
H-27	35.83	30.09	1.97	2.72	2.72	2.72	0.58
H-20	3.85	3.24	0.21	0.29	0.29	0.29	0.06
H-10	8.83	7.42	0.49	0.67	0.67	0.67	0.15
H-19	5.74	3.92	0.26	0.36	0.36	0.36	0.09
H-31	7.28	3.70	0.33	0.83	0.83	0.83	0.12
H-32	9.91	5.04	0.45	1.13	1.13	1.13	0.15
H-1716	2.54	3.39	0.46	0.63	0.63	0.63	0.16
H-1717	1.93	2.58	0.35	0.48	0.48	0.48	0.13
H-22	12.16	10.21	0.67	0.92	0.92	0.92	0.20
H-2410	4.51	4.230	0.58	0.80	0.80	0.80	0.20
H-28 - H-30	14.57	24.39	1.60	2.21	2.21	2.21	0.57
H-401 - H-403	37.60	20.05	2.70	3.73	3.73	3.73	2.47
H-201	3.36	3.10	0.20	0.28	0.28	0.28	0.20
Total	202.97	169.21	13.39	19.40	19.40	19.40	6.14

Combined Heater Projected Emissions

Heater	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
H-13	2.27	1.90	0.13	0.17	0.17	0.17	0.04
H-33	1.24	2.00	0.13	0.18	0.18	0.18	0.05
H-17	18.57	15.54	1.02	1.41	1.41	1.41	0.36
H-37[1]	21.13 [8.95]	17.68	1.16	1.61	1.61	1.61	0.41
H-6	1.12	1.88	0.12	0.17	0.17	0.17	0.04
H-11	13.67	11.48	0.75	1.04	1.04	1.04	0.22
(H-27	35.83	30.09	1.97	2.72	2.72	2.72	0.58
H-20	3.90	3.28	0.21	0.30	0.30	0.30	0.06
H-10	9.02	7.58	0.50	0.69	0.69	0.69	0.15
H-19	5.86	4.01	0.26	0.36	0.36	0.36	0.09
H-31	7.31	3.71	0.33	0.83	0.83	0.83	0.12
H-32	9.94	5.05	0.45	1.13	1.13	1.13	0.16
H-1716	2.67	3.56	0.48	0.66	0.66	0.66	0.17
H-1717	2.02	2.69	0.36	0.50	0.50	0.50	0.13
H-22	12.18	10.23	0.67	0.93	0.93	0.93	0.20
H-2410	4.76	4.53	0.61	0.84	0.84	0.84	0.22
H-28 - H-30	14.59	24.42	1.61	2.22	2.22	2.22	0.57
H-401 - H-403	43.02	22.94	3.09	4.27	4.27	4.27	2.76
H-201	3.44	3.17	0.21	0.29	0.29	0.29	0.19
Total	212.54 [200.36]	175.75	14.06	20.33	20.33	20.33	6.54

[1]Projected emissions for heater H-37 are as if ULNB were not installed. Values in brackets "[}" show projected emissions for heater H-37 with ULNB.

Combined Heater Change in Emissions (Projected – Baseline)

Heater	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
H-13	0.17	0.13	0.01	0.01	0.01	0.01	0.00
H-33	0.09	0.14	0.01	0.01	0.01	0.01	0.00
H-17	1.35	1.13	0.07	0.10	0.10	0.10	0.03
H-37[1]	1.54 [-10.64]	1.28	0.08	0.12	0.12	0.12	0.03
H-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H-11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H-27	0.00	0.00	0.00	0.00	0.00	0.00	0.01
H-20	0.05	0.04	0.00	0.00	0.00	0.00	0.00
H-10	0.19	0.16	0.01	0.01	0.01	0.01	0.00
H-19	0.13	0.09	0.01	0.01	0.01	0.01	0.00
H-31	0.02	0.01	0.00	0.00	0.00	0.00	0.00
H-32	0.03	0.02	0.00	0.00	0.00	0.00	0.00

Combined Heater Change in Emissions (Projected – Baseline)

Heater	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
H-1716	0.13	0.17	0.02	0.03	0.03	0.03	0.01
H-1717	0.09	0.12	0.02	0.02	0.02	0.02	0.00
H-22	0.02	0.02	0.00	0.00	0.00	0.00	0.00
H-2410	0.25	0.24	0.03	0.04	0.04	0.04	0.02
H-28 - H-30	0.02	0.03	0.01	0.01	0.01	0.01	-0.01
H-401 - H-403	5.42	2.89	0.39	0.54	0.54	0.54	0.29
H-201	0.08	0.07	0.01	0.01	0.01	0.01	-0.01
Total Change in emissions[1, 2]	9.57 [8.03]	6.54	0.67	0.93	0.93	0.93	0.41

[1]The change in emissions shown for H-37 is as if ULNB not installed. Values in brackets "[ ]" show the change in emissions with ULNB installed on H-37.
[2] Suncor is not requesting credit for reductions in emissions (shown in red) at this time. Reductions are shown in red. Therefore, any decreases in emissions resulting from this project are set to zero for NSR/PSD analysis.

Reformulated Gasoline (RFG) Project

The purpose of this modification is to approve the necessary modifications to the facility to allow Suncor to produce reformulated gasoline (RFG). Since the Denver Metro/North Front Range (DMNFR) ozone non-attainment area is expected to be downgraded from serious to severe, Suncor will be required to meet the more stringent requirements RFG during the ozone season (May 1 – September 15). RFG has a lower reid vapor pressure (RVP) than the current summer gasoline requirements and are expected to reduce VOC emissions.in the DMVFR area.

In order to meet the RFG requirements, Suncor will need to import more high quality, low RVP blend stocks and decrease the amount of higher RVP blend stocks. Suncor anticipates importing alkylate or iso-octane for blending and exporting light straight run (LSR) gasoline and n-butane. The application indicates that the alkylate/iso-octane would be bottom off-loaded at the Plant 2 rail rack using gravity and pumps, so there will be no venting of emissions to the atmosphere or the rail rack flare (emissions would be realized at the storage tank). Alkylate/iso-octane would be routed to Tank T-28 at Plant 2, transferred to the Plant 1 online blender system and then to one of the finished product storage tanks at Plant 1. Physical modifications will be made to the Plant 1 rail rack to allow for off-loading of alkylate/iso-octane. In addition, new piping components will be installed o accommodate a change in service for various storage tanks. More details on the changes can be found in the technical review document to support the **July 9, 2024** renewal permit.

This project does not increase the design capacity or potential to emit, therefore, the timeframe to monitor emissions from this project is five years after resuming operation upon completion of the project. The RFG project is anticipated to be completed by March 2023.

The applicability analysis related to the RFG modification is included in this appendix. The RFG modification also affected equipment located at Plant 2 of the refinery which is addressed in a separate Title V permit (95OPAD108) but is included here to show the complete analysis.

Except for the new piping components and Tank 24 at Plant 2, which is being returned to service, the units affected by this modification are existing units. Therefore, the major stationary source applicability test is based on a comparison of baseline actual emissions (BAE) to projected actual emissions (PAE). Note that projected actual emissions for the Plant 2 rail rack and the Plant 1 truck rack are based on current permitted emissions. Potential to emit for Tank 24 (Plant 2) was below the APEN de minimis level (1 ton/yr VOC), so an emission limit will not be included in the Plant 2 permit for that tank. Permit limits will be included in both Title V permits for new piping components.

Specific details regarding how BAE and PAE were determined can be found in the technical review document prepared to support the **July 9, 2024** renewal permit.

The resulting emissions increases for the project are shown below:

Emission Unit/Value	**VOC**	**NOx**	**PM (f)[1]**	**PM_{10} (t)[2]**	**$PM_{2.5}$ (t)[2]**	**CO**	**SO_2**
	tpy	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**
Plant 2 Rail Rack							
Baseline	24.71	0.73	0.08	0.08	0.08	3.34	0.00
PAE	37.80	1.10	0.13	0.13	0.13	5.00	0.00
Capable of Accommodating	26.99	0.82	0.09	0.09	0.09	3.73	0.00
Excludable[3]	2.27	0.09	0.01	0.01	0.01	0.39	0.00
Adjusted PAE[4]	35.53	1.01	0.12	0.12	0.12	4.61	0.00
Emissions Increase[5]	**10.81**	**0.28**	**0.03**	**0.03**	**0.03**	**1.27**	**0.00**
Plant 1 Truck Rack							
Baseline	20.78	2.10	0.35	0.35	0.35	11.30	0.00
PAE - Project Only[6]	3.10	0.74	0.08	0.08	0.08	3.39	0.00
PAE	26.56	5.10	0.56	0.56	0.56	23.25	0.00
Capable of Accommodating	23.80	--	--	--	--	--	--
Excludable[3]	3.02	--	--	--	--	--	--
Adjusted PAE (APAE)[4]	23.54	5.10	0.56	0.56	0.56	23.25	0.00
Emissions Increase[7]	**3.10**	**3.00**	**0.21**	**0.21**	**0.21**	**11.95**	**0.00**
No. 1 FCCU							
Baseline	25.74	50.82	55.52	76.34	74.71	4.67	25.39
PAE	28.63	59.99	62.81	86.37	84.53	12.34	33.49
Capable of Accommodating	28.61	59.95	62.77	86.31	84.47	12.33	33.47
Excludable[3]	2.87	9.13	7.25	9.97	9.76	7.66	8.07
Adjusted PAE[4]	25.76	50.86	55.56	76.40	74.77	4.68	25.42
Emissions Increase[5]	**0.02**	**0.04**	**0.04**	**0.06**	**0.06**	**0.01**	**0.02**
No. 2 FCCU							
Baseline	9.53	26.78	19.14	26.32	25.76	3.37	12.36
PAE	11.11	32.77	22.72	31.24	30.57	9.07	19.41
Capable of Accommodating	11.10	32.73	22.69	31.20	30.54	9.06	19.39
Excludable[3]	1.57	5.96	3.55	4.88	4.78	5.69	7.03
Adjusted PAE[4]	9.54	26.81	19.17	26.36	25.80	3.38	12.38
Emissions Increase[5]	**0.01**	**0.04**	**0.03**	**0.04**	**0.04**	**0.01**	**0.02**
No. 3 SRU							
Baseline	0.03	0.60	0.05	0.05	0.05	0.51	40.34
PAE	0.03	0.60	0.05	0.05	0.05	0.51	44.19
Emissions Increase[8]	**1.11E-04**	**2.02E-03**	**1.66E-03**	**1.66E-03**	**1.66E-03**	**0.00**	**3.85**
No. 2 Cat Poly							
Baseline Emissions	--	--	1.86	1.86	1.86	--	--
Projected Actual Emissions	--	--	1.86	1.86	1.86	--	--
Emissions Increase[8]	**--**	**--**	**1.17E-03**	**1.17E-03**	**1.17E-03**	**--**	**--**
Hydrogen Plant (H-2101)							
Baseline Emissions	4.76	35.94	6.65	6.65	6.65	1.08	0.80
Projected Actual Emissions	5.09	45.61	7.03	7.03	7.03	1.13	0.84
Emissions Increase[8]	**0.33**	**9.68**	**0.38**	**0.38**	**0.38**	**0.05**	**0.04**
Tanks[9]							
Baseline Emissions	20.20	--	--	--	--	--	--
Projected Actual Emissions	24.38	--	--	--	--	--	--
Emissions Increase[8]	**5.76**	**--**	**--**	**--**	**--**	**--**	**--**

Emission Unit/Value	**VOC**	**NOx**	**PM (f)[1]**	**PM_{10} (t)[2]**	**$PM_{2.5}$ (t)[2]**	**CO**	**SO_2**
	tpy	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**
Heaters							
Baseline Emissions[10]	9.44	143.02	13.20	13.20	13.20	136.92	--
Projected Actual Emissions[10]	9.57	144.17	13.37	13.37	13.37	138.08	--
Emissions Increase[10]	**0.13**	**1.15**	**0.18**	**0.18**	**0.18**	**1.16**	**0.05**
Plants 1/3 New Fugitive Emissions							
Emissions Increase[11]	**0.81 [0.95[**	**--**	**--**	**--**	**--**	**--**	**--**
Plant 2 New Fugitive Emissions							
Emissions Increase[11]	**2.21 [2.61]**	**--**	**--**	**--**	**--**	**--**	**--**
Emissions Increase	**23.18 [23.72]**	**14.19**	**0.87**	**0.90**	**0.90**	**14.45**	**3.99**
PSD/NANSR Significance Level (T5 Minor Mod Level)[12]	**25**	**25**	**25**	**15**	**10**	**100**	**40**

[1]Condensable PM is not included for purposes of PSD/NANSR applicability for the FCCU (not required, see footnote 2). PM emissions from fuel burning equipment includes condensable PM.

[2]Includes filterable plus condensable particulate matter. Per Reg 3, Part D, Section II.A.40.g condensable PM is included in PM_{10} and $PM_{2.5}$ for purposes of PSD/NANSR applicability.

[3]Excludable emissions equals capable of accommodating minus baseline

[4]Adjusted PAE equals PAE minus excludable emissions.

[5]Change in emissions is adjusted PAE minus baseline.

[6]PAE was determined for project emissions only.

[7]Capable of accommodating emissions were only used to estimate VOC emission increases. Emissions increases for all pollutants except VOC are based on PAE minus baseline. The increase in emissions determined from the applicability analysis cannot exclude emissions from the project. VOC emissions determined by subtracting adjusted PAE minus baseline are less than emissions from the project, so the increase is determined to be emissions from the project.

[8]Change in emissions is PAE minus baseline.

[9]Affected tanks are: Plants 1/3: T-34, T-67, T-72, T-77, T-144, T-775, T-776, T-777 and T-2010 and Plant 2: T-6, T-24, T-25 and T-28. Note that T-24 is treated as a "new" tank, since it is being returned to service. Potential to Emit for that tank was used (0.14 tpy VOC) and since it was below the APEN de minimis level emission limits will not be included for that tank.

[10]A detailed summary of BAE, PAE and the change in emissions for the heaters is included below.

[11]New equipment. Emission increases are based on potential (requested) emissions (actual emission = 0 for new equipment). Note that the source claimed a 100% control level for several pumps by installing technology beyond the requirements for NSPS GGGa, thus the values in brackets "[ ]" represent emissions based on controls estimated for the NSPS GGGa leak detection and control requirements.

[12]Indicates the NANSR significance level for a serious ozone nonattainment area. The area was classified as a serious ozone nonattainment area on January 27, 2020. Note that the area was classified as severe nonattainment for ozone on November 7, 2022.

Heater Summary

Details on BAE, PAE and the change in emissions associated with the heaters are shown in the tables below.

Combined Heater Baseline Emissions

Heater	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
H-101	34.94	34.52	2.27	3.14	3.14	3.14	2.17
H-103	4.43	2.37	0.32	0.59	0.59	0.59	0.30
H-6	1.12	1.88	0.12	0.17	0.17	0.17	0.04
H-11	13.67	11.48	0.75	1.04	1.04	1.04	0.22
H-27	35.83	30.09	1.97	2.72	2.72	2.72	0.58
H-20	3.85	3.24	0.21	0.29	0.29	0.29	0.06
H-10	8.83	7.42	0.49	0.67	0.67	0.67	0.15
H-19	5.74	3.92	0.26	0.36	0.36	0.36	0.09
H-22	12.16	10.21	0.67	0.92	0.92	0.92	0.20
H-2410	4.51	4.30	0.58	0.80	0.80	0.80	0.20
H-28/29/30	14.57	24.39	1.60	2.21	2.21	2.21	0.57
H-201	3.36	3.10	0.20	0.28	0.28	0.28	0.20
Total	143.02	136.92	9.44	13.20	13.20	13.20	4.79

Combined Heater Projected Emissions

Heater	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
H-101	35.05	34.62	2.28	3.15	3.15	3.15	2.11
H-103	4.46	2.38	0.32	0.60	0.60	0.60	0.30
H-6	1.13	1.88	0.12	0.17	0.17	0.17	0.04
H-11	13.69	11.50	0.75	1.04	1.04	1.04	0.22
H-27	35.88	30.14	1.97	2.73	2.73	2.73	0.58
H-20	3.88	3.26	0.21	0.29	0.29	0.29	0.06
H-10	8.85	7.44	0.49	0.67	0.67	0.67	0.14
H-19	5.75	3.93	0.26	0.36	0.36	0.36	0.09
H-22	12.17	10.22	0.67	0.92	0.92	0.92	0.20
H-2410	5.22	4.97	0.67	0.93	0.93	0.93	0.24
H-28/29/30	14.72	24.64	1.62	2.24	2.24	2.24	0.57
H-201	3.37	3.10	0.20	0.28	0.28	0.28	0.19
Total	144.17	138.08	9.57	13.37	13.37	13.37	4.76

Combined Heater Change in Emissions (Projected – Baseline)

Heater	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
H-101	0.10	0.10	0.01	0.01	0.01	0.01	-0.06
H-103	0.03	0.01	0.00	0.00	0.00	0.00	-0.01
H-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H-11	0.02	0.02	0.00	0.00	0.00	0.00	0.00
H-27	0.06	0.05	0.00	0.00	0.00	0.00	0.01
H-20	0.02	0.02	0.00	0.00	0.00	0.00	0.00
H-10	0.02	0.02	0.00	0.00	0.00	0.00	0.00
H-19	0.02	0.01	0.00	0.00	0.00	0.00	0.00
H-22	0.01	0.01	0.00	0.00	0.00	0.00	0.00
H-2410	0.71	0.67	0.09	0.12	0.12	0.12	0.04
H-28/29/30	0.15	0.25	0.02	0.03	0.03	0.03	0.00
H-201	0.01	0.00	0.00	0.00	0.00	0.00	-0.01
Total Change in emissions[1]	1.15	1.16	0.13	0.18	0.18	0.18	0.05

[1] Suncor is not requesting credit for reductions in emissions (shown in red) at this time. Reductions are shown in red. Therefore, any decreases in emissions resulting from this project are set to zero for NSR/PSD analysis.

APPENDIX L

Analyses of Emissions Increases from Various Suncor Projects

GBR Unit Project

In order to meet the Mobile Air Source Toxics rule, which required refiners to reduce the benzene concentration in gasoline, in October 2009 the source submitted an application to install the GBR process unit. The GBR process unit converts benzene in reformate to cyclohexane. The GBR Unit Project was permitted as a minor source in the summer of 2010. Permitted emissions from new equipment associated with the project were kept below the significance level due to throughput limits. As a result, if emissions from the new or modified equipment associated with the project (included in Colorado Construction Permits 09AD1351, 09AD1352 and 10AD1768) are relaxed above the significance level, the PSD review requirements apply. The emissions increases from the project are shown in the table below.

	Emissions (tons/yr)					
	PM	PM_{10}/ $PM_{2.5}$	SO_2	NO_X	CO	VOC
Process Heater H-2410 (GBR unit reboiler, 09AD1351)	1.7	1.7	2.7	9.50	9.0	1.2
GBR project fugitive VOC emissions from equipment leaks (F114, 09AD1352)[1]						9.31
GBR Project Flare (F3, 10AD1768)	1.6	1.6	0.18	14.2	60.5	27.1
Boiler B-4[2, 3, 4]	0.08	0.08	0.35	4.90 [0.65]	0.9	0.06
Boiler B-6[2]	0.08	0.08	0.34	0.41	0.41	0.06
Boiler B-8[2]	0.08	0.08	0.34	0.42	0.42	0.06
Y-3 Cooling Water Tower[2, 5]	0.09	0.09				0.39
Process Heater H-2101 (Hydrogen Plant)[2]	1.62	1.62	1.52	7.83	8.70	1.17
Total[6]	5.25	5.25	5.43	37.26 [33.01]	79.93	39.35
Significance Level[7]	25	15/10	40	40	100	40

[1]Suncor submitted additional info on May 23, 2011 indicating that additional components were installed due to a modification in the design, VOC emissions from the new components were estimated at 0.07 tons/yr. This was discussed in the technical review document of the renewal but the emission limit for the piping components was not correct. The correction will be made with this renewal.

[2]GBR Project non-modified existing equipment at initial permitting (construction permits issued July 22 and August 13, 2010).

[3] NO_X emissions are based on the emission factor (0.464 lb/MMBtu) from the February 22, 2018 performance test.

[4]Values in brackets reflect NO_X emissions based on the emission factor (0.06 lb/MMBtu) relied upon in the Construction Permit (20AD0714) issued on November 23, 2020 for Boiler B-4. Ultra-low NO_X burners (ULNB) were installed on Boiler B-4 to meet emission limits in Regulation No. 7 and Regulation No. 23.

[5]VOC emissions based on current emission calculation methodology for Y-3 cooling tower (El Paso Method, 9.65 ppmv VOC).

[6]Total VOC does not include emissions from new piping components identified in the February 6, 2018 application, as this is “new” equipment. The Division considers that the source obligation provisions apply to equipment installed for the initial permits. Nevertheless, if emissions from these components (0.38 tpy VOC) are included the total would still be below the significance level (39.73 tpy)

[7]Indicates the NANSR significance level on the dates the initial construction permits were issued for the GBR project and the complete minor modification application for this modification to the GBR flare was submitted. Under the provisions of Colorado Regulation No. 3, Part X.I, a source is allowed to make the changes proposed in a complete minor modification application immediately after it is submitted (a construction permit is not required to construct or modify such source per Regulation 3, Part B, Section II.A.6). The area was designated as a serious ozone non-attainment area

on January 27, 2020 and for minor modification applications submitted after that date, the significance level drops to 25 tons/yr of VOC or NO_X. Note that the area was classified as severe nonattainment for ozone on November 7, 2022.

Clean Fuels Project

The source submitted the Clean Fuels Project (CFP) application in January 2004 (revised in February and March 2004) to modify the refinery in order to meet federal requirements to produce low-sulfur gasoline and diesel fuel. The low sulfur fuels must be available in mid-2006. In conjunction with the CFP the source also made some of the modifications required by the Consent Decree (H-01-4430, entered April 30, 2002, Amended August 8, 2003 and October 2006). In addition, the No. 3 Crude Unit (Asphalt Unit) was modified with new metallurgy to process more corrosive (higher acid content) crudes, such as the crude oil derived from oil sands. The CFP involved modifications to existing equipment, as well as new equipment (H_2 Plant, new hydrodesulfurization (HDS) unit (No. 4 HDS), new cooling tower, new tank, new tail gas unit and tail gas incinerator as well as new piping components than piping components such as valves, flanges and connectors which can leak and result in emissions). Note that the CFP is referred to as Project Odyssey in some Suncor literature or references to Suncor.

Emissions from the project did not result in a significant net increase in emissions, thus avoiding PSD review requirements. As a result, if emissions from the new or modified equipment associated with the project are relaxed above the significance level, the PSD review requirements apply. The emissions increases and decreases associated with the project are shown in the table below.

Emission Unit (AIRS pt #)	Status (new/ modified)	Construction Permit (CP) No.	Emissions Increase (tons/yr)[1]					Comments
			PM_{10}	SO_2	NO_X	CO	VOC	
Boilers B-6 and B-8 (021 & 023)	modified	02AD0326 & 02AD0327			-50			The boilers were modified to install low NO_X burners (required by the Consent Decree (CD)). NO_X & CO emissions were decreased, no change to VOC, PM & SO_2 emissions. The CD limited NO_X reductions for netting to 50 tons/yr (see paragraph 219). The actual decrease in NO_X emissions was higher. CO reductions were not necessary, so they are not included.

Emission Unit (AIRS pt #)	Status (new/ modified)	Construction Permit (CP) No.	Emissions Increase (tons/yr)[1]					Comments
			PM_{10}	SO_2	NO_X	CO	VOC	
No. 2 SRU & TGU (022)	modified			-80.2	-8.92			The No. 2 SRU was originally addressed in CP 91AD180-3, it was equipped with a tail gas unit (TGU). Some information in the files indicates that a combustion unit was part of the TGU (presumably this is the source of the NO_X emissions). Emission reductions from the No. 2 SRU were not required by the CD, so there was no restriction on reductions that could be used for netting.
No. 1 SRU (053)	modified							The No. 1 SRU was originally equipped with a tail gas incinerator (no TGU). In the CFP application Suncor indicated that decrease in SO_2 emission was -828 tons/yr but since upgrades to the No. 1 SRU were required by the CD, the reductions were limited to 50 tons/yr per the CD (paragraph 219). Note that the 50 ton/yr allowable reduction was not used as it was not necessary.
TGU Incinerator H-25 (100)	new	04AD0111	0.48	59.72	1.97	2.63	0.35	As part of the CFP project, a tail gas unit (TGU) was installed to treat tail gas from both SRUs. The treated gas leaving the TGU will be routed to an incinerator (H-25). Emissions from both SRUs are covered under H-25 (TGU incinerator).
No. 4 HDS Heater - H-1716 (097)[3]	new	04AD0110	1.73	10.3	7.04	9.39	1.25	The heaters have combined emission limits. For all but SO_2, those limits were assigned to each unit based on design rate. These values add up to the combined limit in the May 24, 2004 CP.
No. 4 HDS Heater H-1717 (098)[3]	new	04AD0110	1.19		4.84	6.45	0.86	
H_2 Plant Heater - H-2101 (096)	new	04AD0109	10.7	10.2	52.19	57.99	7.74	

Emission Unit (AIRS pt #)	Status (new/ modified)	Construction Permit (CP) No.	Emissions Increase (tons/yr)[1]					Comments
			PM_{10}	SO_2	NO_X	CO	VOC	
H_2 Plant Sewers (164)	new						5.20	An application was submitted on July 31, 2017 to bring the H_2 sewers into compliance with NSPS QQQ. In the original CFP application it was presumed that there would be no hydrocarbons in the sewer system and so drains were not included in the original application. Based on the information from the July 31, 2017 application, emissions from the H_2 plant sewer system should have been included in the original CFP analysis and are being included now. Emissions are based on the revised APEN submitted on November 15, 2017.
Tank T774 (104)	new	04AD0114					0.54	
Tank T777 (105)	modified	04AD0115					2.57	CP 04AD0115 issued May 24, 2004 set an emission limit of 2.75 tpy VOC. Actual emissions (2001/2003 average) were 0.18 tpy, increase in emissions is 2.75 - 0.18 = 2.57).
Tank T-52 (141)	modified						-2.03	In the original CFP application, it was presumed that VOC emissions from this tank would be zero, since the tank was being repurposed to store sour water. However, a layer of distillate floats on top of the sour water to minimize volatilization of H_2S, so this tank was permitted for 0.11 tpy VOC in the October 1, 2012 T5 renewal (from a minor mod application submitted on March 3, 2010). The change in emissions is 0.11 minus past (2001/2003 avg) actuals of 2.14 tpy.

Emission Unit (AIRS pt #)	Status (new/ modified)	Construction Permit (CP) No.	Emissions Increase (tons/yr)[1]					Comments
			PM_{10}	SO_2	NO_X	CO	VOC	
Y3 Cooling Tower (156)	new		0.5				1.85	No CP was issued for this unit for the CFP project. PM emissions were below 1 ton/yr & VOC emissions were not estimated. During processing of the May 7, 2014 revised T5 permit, VOC emissions were estimated and above 1 ton/yr, therefore, limits were included in the T5 permit (the cooling tower was not previously permitted). Emissions shown here are based on requested emissions from July 17, 2018 APEN. This APEN was submitted to support the H_2 plant sewer permit application (received July 31, 2017), in order to keep VOC emissions below the significance level.
Debutanizer Fugitives - F108 (091)	new	01AD0363					6.80	The construction permit for this equipment was issued on June 1, 2001. It was considered contemporaneous and included in the netting analysis (project done in 2002).
Asphalt Unit Fugitives - F102 (020)[2, 4]	modified	91AD180-2					1.70	VOC emissions in 5/24/2004 CP was 8.13 tpy. VOC emissions in previous CP (issued 5/17/99) was 6.43 tpy.
No. 2 HDS fugitives - F105 (024)[2]	modified	91AD180-4					1.48	VOC emissions in 5/24/2004 CP was 1.81 tpy. VOC emissions in previous CP (issued 5/17/99) was 0.33 tpy.
No. 3 HDS Fugitives - F103 (008)[2, 4]	modified	91AD180-1					3.37	VOC emissions in 5/24/2004 CP was 23.15 tpy. VOC emissions in previous CP (issued 5/17/99) was 19.78 tpy.
No. 4 HDS Fugitives - F109 (099)[3]	new	04AD0110					7.98	
Tank Farm Fugitives- F112 (103)[2]	modified	04AD0113					5.27	
Tank 52 Piping Fugitives	modified						-6.83	
SWS Sys. Fugitives - F111 (102)[2]	modified	04AD0112					0.12	

Emission Unit (AIRS pt #)	Status (new/ modified)	Construction Permit (CP) No.	Emissions Increase (tons/yr)[1]					Comments
			PM_{10}	SO_2	NO_X	CO	VOC	
Amine Sys. Fugitives - F110 (101)[2]	modified	04AD0111					1.27	
Total			**14.60**	**0.02**	**7.12**	**76.46**	**39.49**	
Significance Level[5]			15	40	40	100	40	

Note that at the time the CFP application was submitted (January 29, 2004) and the permits issued (May 24, 2004), the area in which the source is located was designated attainment or attainment maintenance for all pollutants.

[1]Emissions increase is based on requested emissions (potential to emit (PTE)) for new equipment. For modified equipment that is not noted as "fugitive", the increase is the change in requested (PTE) minus actual (average of 2001 & 2003 emissions). These are essentially the emission limitations included in the Clean Fuels Project (CFP) construction permits (issued May 24, 2004). Decreases in emissions are shown in red.

[2] Fugitive emissions from modified sources are based on the number of piping components added with this modification. This is either the difference between the limit in the May 24, 2004 permit (CFP permit) and the previous permit (for sources with an existing CP at the time the CFP application was submitted) or the limit on the permit issued on May 24, 2004 (the CFP permit).

[3]The No. 4 HDS was modified in 2010 to increase the severity of the unit in order to lower the sulfur content in diesel to 15 ppm (ultra low sulfur). For this project, the burner tips for the heaters were increased (increased heat rate of units) and additional piping components were installed. The revised CP (issued 12/30/2010) included the following emission limits: Heaters: PM/PM_{10} = 3.15 tpy, SO_2 = 10.30 tpy, NO_X = 12.7 tpy, CO = 16.92 tpy and VOC = 2.28 tpy and Fugitives: VOC = 9.68 tpy. Since these emissions increases were due to physical changes and not relaxation of limits, these increases are not included in this analysis of CFP emissions.

[4]New components were added for the No. 3 HDS fugitives - F-103 (CP revised March 1, 2006 to accommodate an additional stream from Plant 2, VOC emissions = 23.82 tpy) and additional components were added to the asphalt unit - F102 in minor modification applications submitted December 22, 2010 and April 5, 2011 (D-133 and wash water drum) that were incorporated into the October 1, 2012 Title V renewal. These modifications increased the VOC emission limit to 9.13 tpy. Since these emission increases were due to physical changes and not relaxation of limits, these increases are not included in this analysis of CFP emissions.

[5]Indicates the significance level at the time the CFP project was permitted (permits issued May 24, 2004).

APPENDIX M

Thermal and Catalytic Oxidizer Compliance Assurance Monitoring Plans

Tank Cleaning and Degassing Thermal Oxidizer (TO)

I. Background

a. Emission Unit Description:

Various Storage Tanks during Cleaning and Degassing Events

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations: Operating Permit Conditions 70.1.1 (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 based on requested emissions indicated on the APEN submitted on February 25, 2022.)

Emission Limitations: VOC 17.2 tons/yr – **Refinery-Wide Limit**

Monitoring Requirements: Thermal Oxidizer (TO) Temperature

c. Control Technology:

When tanks are cleaned and degassed, vapors from the activity are routed to a portable thermal oxidizer. The source relies on a contractor to provide the thermal oxidizer and clean and degas the tanks. Therefore, it is likely that the same portable oxidizer will not be used for every cleaning and degassing event.

II. Monitoring Approach

	Indicator 1
I. Indicator	Combustion Zone Temperature
Measurement Approach	The combustion zone temperature of the thermal oxidizer shall be monitored using a contiuous temperature monitoring device.

	Indicator 1
II. Indicator Range	An excursion is defined as follows: If the TO temperature monitoring system does not have a continuous recorder, an excursion is: • any daily average temperature less than 1,400°F. • failure to record the temperature during a clock hour when tank vapors are routed to the TO. If the TO temperature monitoring system has a continuous recorder, an excursion is any day when the daily average combustion zone temperature is less than 1,400°F when cleaning and degassing emissions are being routed to the TO. When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	The temperature sensor shall be located in the combustion zone, or in ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs. The sensor shall have a minimum accuracy of +/- 1% of the temperature measured.
b. QA/QC Practices and Criteria	Calibration checks of the temperature sensor shall be conducted at least annually. Documentation to indicate the sensor has been calibrated within the last year and such records shall be maintained at the facility and made available to the Division upon request.
c. Monitoring Frequency	Continuous (at least once per hour)
d. Data Collection Procedures	If the temperature monitoring device is not equipped with a continuous recorder, the temperature shall be monitored and recorded at least once per clock hour during periods when tank vapors are routed to the TO. If the temperature monitoring device is equipped with a continuous recording device, daily output from the continuous recording device shall be maintained for each tank cleaning and degassing event.
e. Averaging Time	If hourly temperatures are recorded, the hourly recorded averages shall be used to calculate a daily average, using all the hourly readings during the day. If the temperature monitoring device is equipped with a continuous recorder, the output from the temperature recording device will be reviewed to determine the average operating temperature recorded for each day during periods when vapors are routed to the TO. This value will be used to determine whether there is an excursion. Records shall be kept of the time periods when vapors are routed to the TO.

III. Justification

a. <u>Background:</u>

The pollutant specific emission unit is any storage tank being cleaned or degassed. A portable thermal oxidizer is used during tank cleaning and degassing events. As previously stated the source relies on a contractor to provide the portable thermal oxidizer and perform the tank cleaning and degassing. Thus a different portable thermal oxidizer may be used for tank cleaning and degassing events.

b. Rationale for Selection of Performance Indicators:

The combustion zone temperature was chosen as the indicator because it is an indicator of combustion efficiency. If the chamber temperature decreases significantly, complete combustion may not occur. By maintaining the operating temperature at or above the minimum, a level of control efficiency can be expected to be achieved. In this case, the efficiency is expected to be 95 percent or greater.

c. Rationale for Selection of Indicator Ranges:

As previously stated, the source relies on a contractor to provide the portable thermal oxidizer and clean and degas the tank. Thus a different thermal oxidizer may be used at different times, so a general indicator range was established in order to allow for the possibility of a variety of units. A temperature range of 1,400°F was set as this level is consistent with the requirements for enclosed combustion devices in 40 CFR Part 61 Subpart FF. Specifically § 61.349(a)(2)(i)(C) stipulates that an enclosed combustion device shall be operated at a minimum temperature of 1,400°F, which is designed to reduce organics by 95%.

AIRS Pt 615 – Suncor Western Property Boundary AS/SVE Zones 1 and 2

I. Background

a. Emission Unit Description:

Air Sparge/Soil Vapor Extraction Unit

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations: Operating Permit Conditions 67.1 (Underlying Colorado Construction Permit (CP) 12AD1825)

Emission Limitations: VOC 1.88 tons/yr

Monitoring Requirements: Combustion Zone Temperature

c. Control Technology:

The soil vapor extraction system is equipped with a regenerative thermal oxidizer (RTO), TO-SUN-2 to combust VOC emissions.

II. Monitoring Approach

	Indicator 1
I. Indicator	Combustion Zone Temperature
Measurement Approach	The combustion zone temperature shall be monitored using a temperature sensor.
II. Indicator Range	An excursion is defined as follows: Any daily recorded combustion zone temperature that is less than 1,588°F when SVE vapors are routed to TO-SUN-2. Any day that vapors from the AS/SVE system are routed to the RTO for any time and a temperature is not recorded. When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	The temperature sensor shall be located in the combustion zone, or in ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs. The sensor shall have a minimum accuracy of +/- 1% of the temperature measured.

	Indicator 1
b. QA/QC Practices and Criteria	Calibration checks of the temperature sensor shall be conducted at least annually. Records of each calibration check shall be maintained and made available to the Division upon request.
c. Monitoring Frequency	Continuous (at least once per hour)
d. Data Collection Procedures	The TO combustion zone temperature shall be monitored continuously using a temperature monitoring device and recorded daily in a log on any day that vapors from the AS/SVE system are routed to the RTO. The temperature log shall be made available to the Division upon request.
e. Averaging Time	None.

III. Justification

a. Background:

The pollutant specific emission unit is the AIRS pt 615 – Suncor Western Propery Boundary Zones 1 and 2 AS/SVE system. The remedation system collects vapors from soil and groundwater remedication systems, which consists of two (2) blowers which are routed to a regenerative thermal oxidizer.

b. Rationale for Selection of Performance Indicators:

The combustion zone temperature was chosen as the indicator because it is an indicator of combustion efficiency. If the chamber temperature decreases significantly, complete combustion may not occur. By maintaining the operating temperature at or above the minimum, a level of control efficiency can be expected to be achieved.

c. Rationale for Selection of Indicator Ranges:

A compliance test was conducted on the RTO on Febuary 24, 2015 to assess compliance with the VOC emission limit for AIRS pt 615. The temperature monitor measures the chamber control temperature, thus 1,588 °F (minimum value) was set as the indicator range.

The results of the February 24, 2015 test are shown in the table below:

Temperature (°F)				Test Results Emissions
Set Point	Chamber Control	Chamber 1	Chamber 2	
1,550	1,588	1,589	1,591	VOC – 0.10 tpy

AIRS Pt 617 – RPC AS/SVE Zone 2 (East)

I. Background

a. Emission Unit Description:

Air Sparge/Soil Vapor Extraction Unit

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations:	Operating Permit Conditions 67.1 (Underlying Colorado Construction Permit (CP) 12AD1825)
Emission Limitations:	VOC 1.2 tons/yr
Monitoring Requirements:	Catalyst Inlet Temperature

c. Control Technology:

The soil vapor extraction system is equipped with an electric catalytic oxidize (CO-RPC-1) to oxidize VOC emissions.

II. Monitoring Approach

	Indicator 1
I. Indicator	Catalyst Inlet Temperature
Measurement Approach	Catalyst inlet temperature shall be monitored using a temperature sensor.
II. Indicator Range	An excursion is defined as follows: Any recorded catalyst inlet temperature that is less than 775°F Any day that vapors from the AS/SVE system are routed to the catalytic oxidizer for any time and a temperature is not recorded. When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	The temperature sensor shall be located prior to the catalyst. The sensor shall have a minimum accuracy of +/- 1% of the temperature measured.
b. QA/QC Practices and Criteria	Calibration checks of the temperature sensor shall be conducted at least annually. Records of each calibration check shall be maintained and made available to the Division upon request.
c. Monitoring Frequency	Daily

	Indicator 1
d. Data Collection Procedures	The catalyst inlet temperature shall be monitored continuously using a temperature monitoring device and recorded daily in a log on any day that vapors from the AS/SVE system are routed to the RTO. The temperature log shall be made available to the Division upon request.
e. Averaging Time	None.

III. Justification

a. Background:

The pollutant specific emission unit is the AIRS pt 615 – RPC Zone 2 AS/SVE system. The remedation system collects vapors from soil and groundwater remedication systems, which consists of two (2) blowers which are routed to an electric catalytic oxidizer.

b. Rationale for Selection of Performance Indicators:

The catalyst inlet temperature was chosen as the indicator because it is an indicator of efficient oxidation.

c. Rationale for Selection of Indicator Ranges:

A compliance test was conducted on the catalytic oxidizer on Febuary 25, 2015 to assess compliance with the VOC emission limit for AIRS pt 617. The catalyst inlet temperature was 775°F during the test, thus 775°F (minimum value) was set as the indicator range. The results of the February 24, 2015 test are shown in the table below:

Main Temperature pre-Catalyst (°F)	Test Results Emissions
775	VOC – 0.01 tpy

Plant 1 Wastewater Treatment System RTO and API Headworks Carbon Canisters

I. Background

a. Emission Unit Description:

Plant 1 Wastewater treatment system equipment.

d. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations: Operating Permit Conditions 23.1.3 (As provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7 based on the emissions requested on the APEN submitted April 8, 2015, red-lined May 14, 2015)

Emission Limitations: VOC 15.7 tons/yr

Monitoring Requirements: RTO - Combustion Zone Temperature
Carbon Canisters - Breakthrough

e. Control Technology:

Emissions from the API headworks, API lift station, T60 lift station and the centrifuge are routed to an RTO to reduce VOC emissions. In the future additional equipment may be routed to the RTO. When the RTO is not in operation emissions from the API headworks, API lift station, T60 lift station and the centrifuge are routed to carbon canisters (two canisters in series). Uncontrolled VOC emissions from the API headworks exceed the major source level, so CAM applies to the API headworks, when emissions are vented to the RTO or carbon canisters.

II. Monitoring Approach

	RTO	Carbon Canisters
	Indicator 1	Indicator 1
I. Indicator	Combustion Zone Temperature	Breakthrough
Measurement Approach	The combustion zone temperature shall be monitored using a temperature sensor.	The permittee shall monitor for breakthrough between the primary and secondary carbon canisters for the API headworks daily at times when there is flow to the carbon canisters.

	RTO	Carbon Canisters
	Indicator 1	Indicator 1
II. Indicator Range	An excursion is defined as follows: Any rolling 3-hour period in which the combustion zone temperature is less than 1,573 °F. The combustion zone temperature was set by a performance test conducted on March 13, 2024. This value will be revised based on the results of any future compliance tests as specified in Condition 23.11.4.	An excursion is defined as follows: Any daily breakthrough reading of 5 ppm benzene or more. Any day in which vapors from the API headworks are routed to carbon canisters and breakthrough is not monitored.
	When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.	
III. Performance Criteria		
a. Data Representativeness	The temperature sensor shall be located in the combustion zone, or in ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs. The sensor shall have a minimum accuracy of +/- 1% of the temperature measured.	The permittee shall monitor for breakthrough between the primary and secondary canisters using an UltraRae 3000 or equivalent portable analyzer capable of detecting benzene levels < 5 ppm.
b. QA/QC Practices and Criteria	Calibration checks of the temperature sensor shall be conducted at least annually. Records of each calibration check shall be maintained and made available to the Division upon request.	The portable analyzer shall be calibrated and maintained in accordance with manufacturer's recommendations and good engineering practices. A copy of operating and maintenance procedures, schedules for maintenance and/or calibration activities and records related to maintenance of the portable monitoring device and good engineering practices such as records of inspection, repair, or replacement shall be made available to the Division upon request.
c. Monitoring Frequency	Continuous	Daily
d. Data Collection Procedures	The RTO combustion zone temperature shall be monitored continuously using a temperature monitoring device with a continuous recorder.	When vapors from the API headworks are routed to carbon canisters, the permittee shall monitor for breakthrough between the primary and secondary carbon canisters at times there is actual flow to the carbon canister daily.

	RTO	Carbon Canisters
	Indicator 1	Indicator 1
e. Averaging Time	Data from the continuous recorder shall be reduced to hourly averages and used in a 3-hr rolling average. The RTO is equipped with a temperature sensor in each chamber. The data acquisition system collects the temperature readings for both combustion chambers and selects the lower value (15-minute average) of the two for use in the 3-hour rolling average.	None.

III. Justification

a. Background:

The pollutant specific emission unit is the Plant 1 WWTS equipment routed to the RTO and the API headworks. Emissions from the API headworks, API lift station, T60 lift station and the centrifuge are routed to an RTO to reduce VOC emissions. In the future additional equipment may be routed to the RTO. During periods of RTO downtime, equipment normally controlled by the RTO are routed to carbon canisters (two canisters in series). The API headworks had uncontrolled VOC emissions above the major source threshold, so when emissions from the API headworks are routed to the RTO or carbon canisters, CAM applies.

b. Rationale for Selection of Performance Indicators:

For the RTO, the combustion zone temperature was chosen as the indicator because it is an indicator of combustion efficiency. If the chamber temperature decreases significantly, complete combustion may not occur. By maintaining the operating temperature at or above the minimum, a level of control efficiency can be expected to be achieved.

For carbon canisters, breakthrough was chosen as the indicator as VOC or benzene emissions detected at the carbon canister exhaust is an indicator the carbon can no longer effectively adsorb hydrocarbons. For the API headworks a set of two carbon canisters in series are used and the permittee is required to monitor for breakthrough between the carbon canisters, not at the outlet of the second carbon canister.

c. Rationale for Selection of Indicator Ranges:

For the carbon canisters, an excursion from the indicator range is a daily breakthrough reading of 5 ppm benzene or more on any day in which vapors from the API headworks are routed to carbon canisters, or any day in which vapors from the API headworks are routed to the carbon canisters and breakthrough is not monitored. Per Condition 23.1.3, the permitted emissions limit of 15.7 tons of VOC per year assumes a carbon canister VOC control efficiency of 98 percent (%), an inlet VOC concentration of 150,000 ppmvd from the API headworks, and an inlet of 50 scfm from the API headworks. The detailed emissions calculations associated with establishing the limit also specify an inlet benzene concentration of 2,000 ppmvd. Based on the inlet VOC and benzene concentration values that underly the 15.7 ton per year VOC emission limitation, a 98% VOC control efficiency is associated with a VOC breakthrough concentration of 3,000 ppmvd and a benzene breakthrough concentration of 40 ppmvd. A benzene breakthrough concentration of 5 ppmvd is associated with a 99.75% control efficiency. Additionally, breakthrough monitoring is conducted between the primary and secondary carbon canisters which ensures that the secondary carbon canister continues to achieve control even after the primary canister has experienced breakthrough.

For the purposes of demonstrating compliance with the Benzene Waste Operations NESHAP (BWON) requirements, the Consent Decree (CD) defined breakthough between the primary and secondary carbon canisters as 50 ppm VOC (H-01-4430, paragraph 90), although the CD also allowed the source to “conduct a study of the effectiveness of the benzene and VOC limits proposed under this paragraph for dual carbon canisters”. The study shall be designed to determine the concentration of VOCs or benzene that may be emitted from the primary (lead) carbon canister in a dual series before VOCs above background or benzene above 1 ppm is emitted from the secondary (tail) carbon canister”. Presumably the source conducted that study and a breakthrough of 5 ppm benzene was approved. Note that paragraph 141 of the Plant 2 CD (No. SA-05-CA-0569, entered November 23, 2005) defines breakthrough between the primary and secondary carbon canisters as 5 ppm benzene.

Per §64.4(b) of the CAM rule, “To justify the appropriateness of the monitoring elements proposed, the owner or operator may rely in part on existing applicable requirements that establish the monitoring for the applicable pollutant-specific emissions unit or a similar unit.” The 5 ppm breakthrough definition is consistent with the Consent Decree BWON monitoring requirements and demonstrates a control efficiency greater than 98% based on the emissions calculations that were used to establish the annual VOC limit of 15.7 tons per year. Therefore, 5 ppm benzene is an appropriate indicator range.

For the RTO, an excursion from the indicator range is any 3-hour period in which the combustion zone temperature is less than 1,573 °F, which is based on a performance test conducted on March 13, 2024. Per Condition 23.1.3, the permitted emissions limit of 15.7 tons of VOC per year assumes an RTO VOC control efficiency of 99 percent and an hourly controlled VOC emission rate of 2.57 pouns per hour. Compliance tests were conducted for the Plant 1 WWTS RTO on June 2, 2015 and again on May 24, 2016 and March 13, 2024 when more emission units were routed to it. The compliance test results demonstrated that the controlled VOC emission rate remained below 2.57 pounds per hour during both performance tests that were used to assess the RTO’s performance with respect to VOC control. The indicator value is set at the level from the most recent compliance test and will be revised should future compliance tests be conducted (the permit requires a compliance test if additional emission units are routed to the RTO).

Additionally, the compliance tests were required by the BWON per §61.355(i) to assess compliance with organic emissions reduction requirement in §61.349(a)(2)(i)(A), (B), or (C). The CAM plan requires the temperature monitoring system and continuous recorder to reduce temperature data to 1-

hour averages and use those in a 3-hour rolling average. This is consistent with the BWON recordkeeping requirements in 61.356(j)(4).

Since the Plant 1 WWTS monitors the temperature in both combustion chambers and the data acquisition and handling system relies on the lowest temperature, the minimum temperature is set at the lower of the two values determined from the March 13, 2024 compliance test.

The results of the compliance tests are shown in the table below:

Parameter	June 2, 2015 Compliance Test	May 24, 2016 Compliance Test	March 13, 2024 Compliance Test	Limitation
VOC Emissions (lb/hr)	0.18	0.34	032	2.57
Control Efficiency (%)	99	99.5	98	95
Temperature Set Point (°F)	1,575	1,572	1,574	
Chamber 1 Temp (°F)	1,582	1,580	1,582	
Chamber 2 Temp (°F)	1,593	1,578	1,573	

APPENDIX N

Flare and Vapor Combustion Unit (VCU) Compliance Assurance Monitoring Plans

R101 – Rail Loading Rack and Enclosed Vapor Combustion Unit (VCU)

I. Background

a. Emission Unit Description:

The rail loading rack loads gasoline, jet fuel and distillates into rail cars and unloads ethanol from rail cars into storage tanks.

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations:	Operating Permit Conditions 24.1.1 (Underlying Colorado Construction Permit (CP) 88AD012)
Emission Limitations:	VOC 12.5 tons/yr
Monitoring Requirements:	Combustion zone temperature

c. Control Technology:

Vapors from loading the various products and unloading ethanol (from ethanol deaerators and depressurizing rail cars) are routed to a vapor combustion unit (VCU).

II. Monitoring Approach

	Indicator 1
I. Indicator	Combustion Zone Temperature
Measurement Approach	The combustion zone temperature shall be monitored using a temperature sensor.

	Indicator 1
II. Indicator Range	An excursion is defined as follows: Any 6-hour rolling period in which the combustion zone temperature is less than 1,299°F. The combustion zone temperature was set by a performance test conducted on April 18, 2019. This value will be revised based on the results of any future compliance tests as specified in Condition 24.12. When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	The temperature sensor shall be located in the combustion zone, or in ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs. The sensor shall have a minimum accuracy of +/- 1% of the temperature measured.
b. QA/QC Practices and Criteria	Calibration checks of the temperature sensor shall be conducted at least annually. Records of each calibration check shall be maintained and made available to the Division upon request.
c. Monitoring Frequency	Continuous
d. Data Collection Procedures	A continuous temperature monitoring system shall be used to monitor temperature in the combustion zone.
e. Averaging Time	Temperature data recorded shall be reduced to hourly averages and used in a 6-hour rolling average. Only those 1-minute values recorded during periods when gasoline, distillates and/or jet fuel is being loaded or ethanol is being unloaded, i.e. when the waste gas valve to the VCU is in the "open" position, are required to be used in the 6-hour rolling averages. Periods when only pilot or assist gases are being combusted, i.e. when the waste gas valve to the VCU is in the "closed" position, shall not be used to calculate the 6-hour rolling averages.

III. Justification

a. Background:

The pollutant specific emission unit is the rail loading rack which loads gasoline, jet fuel, and distillates into rail cars. In addition, vapors from unloading ethanol rail cars are routed to a VCU. The VCU was installed in December 2018, the rail loading rack was previously equipped with a flare.

b. Rationale for Selection of Performance Indicators:

The combustion zone temperature was chosen as the indicator because it is an indicator of combustion efficiency. If the chamber temperature decreases significantly, complete combustion may not occur. By maintaining the operating temperature at or above the minimum, a level of control efficiency can be expected to be achieved.

The rail rack is used to load gasoline, distillates, and jet fuel, and to unload ethanol. Vapors from loading and unloading these materials are routed to the VCU. The permitted emissions limit of 12.5 tons of VOC per year, which is subject to CAM, assumes an emission factor of 10 milligrams of total organic compounds (TOC) per liter (mg/L) of gaoline loaded, and a control efficiency of 98% for loading and unloading of distillate, jet fuel, and ethanol. As discussed below, the compliance test indicated that the control efficiency of the VCU exceeded 98% and that the outlet VOC concentration remained below 10 mg/L when loading both gaoline and distillate.

c. Rationale for Selection of Indicator Ranges:

The Rail Loading Rack is subject to the gasoline loading rack provisions of 40 CFR Part 63, Subpart CC (Conditions 24.5, 24.8, and 53). A compliance test was conducted on the rail rack VCU on April 16 – 18, 2019 to assess compliance with the 10 mg/L emission factor and to verify the control efficiency. The 10 mg/L emission factor during gasoline loading is equivalent to the MACT CC emission limit during gasoline loading, per 40 CFR §63.650(a) and §63.422(b). Additionally, MACT CC requires completion of a performance test and establishing an operating parameter value (i.e., combustion zone temperature) per 40 CFR §63.650(a) and §63.425(a) and (b). The results of April 2019 test are shown in the table below:

Test Description	Outlet VOC (lb/hr)	Outlet VOC (mg/l)	Control Efficiency (%)	Combustion Chamber Temperature (°F)
Distillate Control Efficiency[1] April 16, 2019	0.0351	0.115	99.86	1,235
Gasoline Control Efficiency[1] April 17, 2019	0.0443	0.093	99.96	1,320
MACT CC Test[2] April 18, 2019	0.060	0.159	99.95	1,299

[1]Control efficiency tests consistent of three one-hour test runs.
[2]Conducted in accordance with the provisions in 63.425(a) and recorded the parameter to be monitored as specified in 63.425(b) (6-hour test run with at least 300,000 liters of gasoline loaded).

The performance test results demonstrated that the VOC control efficiency exceeded 98% and the outlet VOC concentration remained below 10 mg/L during the three test runs that were used to assess the VCU's performance with respect to VOC control. For the purpose of establishing the operating parameter values as required per MACT CC, it was determined that the VCU shall be operated at a minimum of 1,299 °F on a 6-hour rolling average basis.

Per §64.3(a) of the CAM rule:
(1) The monitoring approach must be designed to provide data for one or more indicators of performance of the control device, and
(2) The owner or operator shall establish an appropriate range(s) or designated condition(s) for the selected indicator(s) such that operation within the ranges provides a reasonable assurance of ongoing compliance with emission limitations or standards for the anticipated range of operating

conditions. MACT CC requires establishing the operating parameter value to monitor the performance of the VCU
with respect to VOC control and ensure compliance with the 10 mg/L outlet VOC emission limit. For determining compliance with the 12.5 ton/year VOC emission limit to which the CAM requirements apply, the 10 mg/L VOC emission limit is used during gasoline loading and a control efficiency of 98% is used for loading/unloading of distillate, jet fuel, and ethanol.

The compliance test indicated that the control efficiency exceeded 98% and that the outlet VOC concentration remained below 10 mg/L during the test run used to establish the MACT CC operating parameter minimum value of 1,299 °F on a 6-hour rolling average basis. Therefore, the selection of a CAM monitoring approach that is consistent with the current MACT CC operating parameter value is appropriate.

R102 – Truck Loading Rack and Flare

I. Background

a. Emission Unit Description:

The truck loading rack loads gasoline and distillates into tanker trucks.

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations: Operating Permit Condition 25.1.1 (Underlying Colorado Construction Permit (CP) 86AD450)

Emission Limitations: VOC 26.6 tons/yr

Monitoring Requirements: Presence of a pilot flame

c. Control Technology:

Vapors from loading gasoline and distillate are routed to an open flare. The permit includes provisions to operate a back-up flare. This CAM plan applies to both the permanent flare and any temporary flare used as allowed in Condition 25.15.

II. Monitoring Approach

	Indicator 1
I. Indicator	Presence of a pilot flame
Measurement Approach	The presence of a flare pilot flame shall be continuoutly monitored using a heat-sensing device, such as an ultraviolet beam sensor or a thermocouple to indicate the presence of a flame..
II. Indicator Range	An excursion is defined as follows: Any period when vapors from gasoline and distillate loading are routed to the flare and • the presence of a pilot flame is not detected. • the pilot flame monitoring device is inoperable. When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	The thermocouple or heat-sensing device must be installed in proximity to the pilot light to indicate the presence of a flame.

	Indicator 1
b. QA/QC Practices and Criteria	The flare, heat sensing device and any associated instrumentation and control system logic shall be operated and maintained in accordacnce with manufacturer's recommendations and good engineering practices. A copy of operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to maintenance of the flare, heat sensing device, associated instrumentation and control system logic and good engineering practices such as records of inspection, repair, or replacement shall be made available to the Division upon request.
c. Monitoring Frequency	Continuous
d. Data Collection Procedures	A heat-sensing device shall be used to indicate the presence of a flame. Records shall be kept of the periods the pilot flame is out or the heat-sensing device is inoperable.
e. Averaging Time	None

III. Justification

a. Background:

The pollutant specific emission unit is the truck loading rack which loads gasoline and distillates into tank trucks. Vapors from loading these materials are routed to an open flare.

b. Rationale for Selection of Performance Indicators:

The destruction of VOC emissions is dependent upon combustion. The flare is equipped with a thermal device to ensure that a flame is present. If no flame is present then combustion will not occur.

c. Rationale for Selection of Indicator Ranges:

Since VOC reduction is based on combustion and combustion does not occur without a pilot flame, the lack of a pilot flame or failure of the pilot monitoring device are appropriate indicators that the flare may not be functioning properly.

Monitoring is defined in 40 CFR §64.1 of the CAM Rule to include "continuous process . . . or other relevant parameter monitoring systems or procedures." CAM Plans must meet the "general criteria" in §64.3 which incldues requirements to design monitoring to "obtain data for one or more indicators of emission control performance" and can include conditions "expressed as maintaining the applicable parameter in a particular operational status or designated condition" (§64.3(a)(1)-(3)).

Monitoring for presence of pilot flame meets all general criteria for monitoring and establishing an indicator range for CAM compliance: presence of flame ensures adequate destruction efficiency (§64.3(a)(1)); on/off of flame is indicative of flare performance (§64.3(a)(3), (b)(1)); and monitoring for presence of a flame is continuous (§64.3(b)(4)).

The Truck Loading Rack Flare is subject to the closed vent system and control device requirements of the BWON. Per Section II, Conditions 25.7, 25.12, 57, and 65.17.2.3, the Truck Loading Rack Flare is subject to the requirements of 40 CFR 60.18. Condition 57.2 requires continuous monitoring of the presence of a flame using a thermocouple or any other equivalent device per 40 CFR 60.18(f). Condition 57.7 also requires monitoring -- consistent with §60.18(d) – to ensure the flare is operated in accordance with manufacturer specifications.

The continuous monitoring of the presence of a flame and operation in conformance with the design of the Truck Loading Rack Flare is sufficient to meet CAM. 40 CFR §64.4(b)(5) provides that "acceptable monitoring includes . . . monitoring identified in guidance by EPA." EPA CAM-Specific Guidance confirms that §60.18 monitoring is "acceptable monitoring" for CAM. EPA confirms per their Technical Guidance Document: Compliance Assurance Monitoring (p. 3-10, Aug. 1998) that the "continuous monitoring of the presence of a pilot flame (yes/no)" is acceptable for CAM because "[i]f the sensor fails, the lack of a pilot flame will be indicated and corrective action will be required." EPA specifically clarified that additional monitoring of "indicator ranges" beyond what is required in §60.18 is not necessary (p. 191 of EPA's October 2, 1997 Responses to Public Comments, Part III):

> *Part 64 recognizes several situations for which additional justification or testing for establishing monitoring or indicator ranges is not necessary. The preamble to the final rule clarifies that, in accordance with § 64.4(b)(5), no additional justification is necessary for the operation and monitoring of flares covered by design criteria in 40 CFR 60.18.*

The CAM requirements are met because the Truck Rack Flare requires a thermocouple to continuously monitor presence of a pilot flame and for monitoring for conformance with its design. The Truck Rack Flare is also required to comply with the other applicable provisions of §60.18. For instance, the Truck Rack Flare is required per Condition 57 to meet all §60.18 requirements, including daily checks on visible emissions and ensuring conformance with design requirements such as exit velocity. The CAM requirements are satisfied since monitoring for the presence of a pilot flame is continuous and all of the elements of the monitoring approach satisfy the requirements of CAM.

F2 & F3 - Plant 3 (AU) and GBR Flares

I. Background

a. Emission Unit Description:

Multiple process vents, pressure relief devices and other flare tie-ins.

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations:	Operating Permit Condition 30.1 (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part B, Section II.A.6 and Part C, Section X, based on requested emissions on the APEN submitted September 12, 2017, red-lined October 24, 2018) Operating Permit Condition 31.1 (Underlying Colorado Construction Permit (CP) 10AD1768)		
Emission Limitations:	Plant 3 (AU) Flare (F2)	VOC	8.6 tons/yr
	GBR Flare (F3)	VOC	27.1 tons/yr
Monitoring Requirements:	Presence of the pilot flame(s) Net heating value of flare combustion zone gas		

c. Control Technology:

Vapors from mutiple process vents, pressure relief devices and other tie-ins are routed to both the Plant 3 and GBR flares.

II. Monitoring Approach

	Indicator 1	Indicator 2	Indicator 3	Indicator 4	Indicator 5
I. Indicator	Presence of a pilot flame(s)	Net heating value of flare combustion zone gas.	Visible emissions	Flare tip velocity (V_{tip})	Net heating value dilution parameter (NHC_{dil}) (For the Plant 3 (AU) flare only when receiving perimeter assist air)

Measurement Approach	The presence of the flare pilot flame(s) shall be continuously monitored using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present, in accordance with 40 CFR §63.670(g)).	NHVcz shall be determined in accordance with 40 CFR §63.670(m), as applicable. Except as provided in §63.670(j)(5) and (6) of this section, a calorimeter capable of Continuously measuring, calculating, and recording NHV_{vg} at standard conditions shall be installed, operated, calibrated, and maintained in accordance with 40 CFR §63.670(j)(3). A monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas may, optionally, be installed, operated, calibrated, and maintained, in accordance with 40 CFR §63.670(j)(4). NHVvg shall be determined based on the composition monitoring data on a 15-minute block average basis according to the requirements in 40 CFR §63.670(l). Flare vent gas, steam assist and air assist flow rates shall be continuously monitored in accordance with 40 CFR §63.670(i).	Visible emissions Observations must be conducted in accordance with the methods in 40 CFR §63.670(h).	Flare tip velocity (Vtip) shall be monitored using the procedures in 40 CFR §63.670(i) and §63.670(k). Flare vent gas flow rate shall be continuously monitored in accordance with 40 CFR §63.670(i). Vtip shall be determined on a 15-minute block average basis, in accordance with 40 CFR §63.670(k).	NHVdil shall be determined in accordance with 40 CFR §63.670(n), only during periods when perimeter assist air is used, as applicable. Except as provided in §63.670(j)(5) and (6) of this section, a calorimeter capable of continuously measuring, calculating, and recording NHV_{vg} at standard conditions shall be installed, operated, calibrated, and maintained in accordance with 40 CFR §63.670(j)(3). A monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas may, optionally, be installed, operated, calibrated, and maintained, in accordance with 40 CFR §63.670(j)(4). NHVvg shall be determined based on the composition monitoring data on a 15- minute block average basis

	Indicator 1	Indicator 2	Indicator 3	Indicator 4	Indicator 5
					according to the requirements in 40 CFR §63.670(l). Flare vent gas, steam assist and air assist flow rates shall be continuously monitored in accordance with 40 CFR §63.670(i).
II. Indicator Range	An excursion is defined as follows: Each 15-minute block during which there is at least one minute where no pilot flame is present when waste gas is routed to the flare. Excursions in different 15-minute blocks from the same event are considered separate excursions.	An excursion is defined as follows: Each 15-minute block period when waste gas is routed to the flare for at least 15-minutes and the net heating value of flare combustion zone gas (NHV_{CZ}) is less than 270 Btu/scf, as calculated in accordance with the requirements of 40 CFR §63.670(m).	An excursion is defined as follows: A two-hour block period during which waste gas is routed to the flare, the flare vent gas flow rate is less than the smokeless design capacity, and visible emissions are observed for a total of 5 minutes or more, as determined in accordance with 40 CFR §63.670(h).	An excursion is defined as follows: Each 15-minute block period during which waste gas is routed to the flare for at least 15-minutes, the flare vent gas flow rate is less than the smokeless design capacity of the flare, and the flare tip velocity equals or exceeds the applicable maximum flare tip velocity specified in 40 CFR §63.670(d).	An excursion is defined as follows: Each 15-minute block period during which waste gas is routed to the flare for at least 15-minutes, the flare is actively receiving perimeter assist air, and NHV_{dil} is below 22 Btu/scft2, as calculated in accordance with the requirements in 40 CFR §63.670(n), unless the conditions in 40 CFR §63.670(f)(1) are met.
	When an excursion occurs, corrective actions will be initiated beginning with an evaluation of the occurrence to determine the action required to correct the situation. A history of the corrective action(s) will be maintained at the facility and made available upon request.				
III. Performance Criteria					

	Indicator 1	Indicator 2	Indicator 3	Indicator 4	Indicator 5
a. Data Representativeness	Continuous parameter Monitoring systems (CPMS) shall meet the flare monitoring system requirements of 40 CFR §63.671, as applicable.	Continuous parameter monitoring systems (CPMS) shall meet the flare monitoring system requirements of 40 CFR §63.671, as applicable.	Visible emissions observations must be conducted using Method 22 at 40 CFR Part 60, Appendix A-7 or a video surveillance camera must be used to continuously record images of the flame at an angle suitable for visual emissions observations, in accordance with the requirements of 40 CFR §63.670(h).	Continuous parameter monitoring systems (CPMS) shall meet the flare monitoring system requirements of 40 CFR §63.671, as applicable.	Continuous parameter monitoring systems (CPMS) shall meet the flare monitoring system requirements of 40 CFR §63.671, as applicable.
b. QA/QC Practices and Criteria	Continuous parameter monitoring systems (CPMS) shall meet the flare monitoring system requirements of 40 CFR §63.671, as applicable.	All monitoring equipment must meet the minimum accuracy, calibration and quality control requirements specified in table 13 of 40 CFR 63 Subpart CC, in accordance with 40 CFR §63.671(a)(1).	Visible emissions observations must be conducted using Method 22 at 40 CFR Part 60, Appendix A-7 or a video surveillance camera must be used to continuously record images of the flame at an angle suitable for visual emissions observations, in accordance with the requirements of 40 CFR §63.670(h).	All monitoring equipment must meet the minimum accuracy, calibration and quality control requirements specified in table 13 of 40 CFR 63 Subpart CC, in accordance with 40 CFR §63.671(a)(1).	All monitoring equipment must meet the minimum accuracy, calibration and quality control requirements specified in table 13 of 40 CFR 63 Subpart CC, in accordance with 40 CFR §63.671(a)(1).

	Indicator 1	Indicator 2	Indicator 3	Indicator 4	Indicator 5
c. Monitoring Frequency	Continuous at all times when waste gas is routed to the flare, in accordance with 40 CFR §63.671(a)(4).	Continuous at all times when waste gas is routed to the flare, in accordance with 40 CFR §63.671(a)(4).	At least once per day, or at any time that visible emissions are observed, while waste gas is routed to the flare, in accordance with 40 CFR §63.670(h)(1), or continuously when waste gas is routed to the flare, in accordance with 40 CFR §63.670(h)(2).	Continuous at all times when waste gas is routed to the flare, in accordance with 40 CFR §63.671(a)(4).	Continuous at all times when waste gas is routed to the flare, in accordance with 40 CFR §63.671(a)(4).
d. Data Collection Procedures	Flare monitoring records shall be kept according to the requirements in 40 CFR §63.655(i)(9), as applicable.				
e. Averaging Time	15-minute block periods	15-minute block average	2-hour block period	15-minute block average	15-minute block average
f. Exceedance	Not directly applicable.				

III. Justification

a. Background:

As discussed in more detail in the technical review document to support this renewal **[issue DATE]**, the Division is including this CAM plan in response to EPA's objection on the Plant 2 renewal permit **[issue DATE]** that exempted the Plant 2 refinery flare from CAM. This CAM Plan was revised after the public comment period to incorporate all relevant monitoring provisions for flares in 40 CFR Part 63, Subpart CC (MACT CC).

b. Rationale for Selection of Performance Indicators and Indicator Ranges:

The destruction of VOC emissions through combustion in a flare is dependent upon proper operation and maintenance of the flare. In 2015, EPA promulgated revised regulations under 40 CFR Part 63, Subpart CC, "National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries" (MACT CC), that included new flare operating requirements to ensure that flares meet the required performance level (98% destruction efficiency). EPA identified five parameters to monitor to assure a flare maintains a high destruction efficiency: presence of a pilot flame, the net heating value in the combustion zone (NHVCZ), visible emissions, flare tip velocity, and (for air-assisted flares only) net heating value dilution parameter (NHVdil) [80 Fed. Reg. 75178 (Dec. 1, 2015)]

In the preamble to the final Refinery Sector Rule revisions (80 FR 75178, December 1, 2015), EPA notes the following on page 75211:

> Based on the results of all of our analyses, the EPA is finalizing a single minimum NHVcz operating limit for flares subject to the Petroleum Refinery MACT standards of 270 BTU/scf during any 15- minute period. The agency believes, given the results from the various data analyses conducted, that this operating limit is appropriate, reasonable and will ensure that refinery flares meet 98-percent destruction efficiency at all times when operated in concert with the other suite of requirements refinery flares need to achieve (e.g., flare tip velocity requirements, visible emissions requirements, and continuously lit pilot flame requirements).

The presence of a pilot flame is proven to improve flare flame stability and ensure flare performance [88 Fed. Reg. 25080, 25149 (April 25, 2023)]. Higher NHVcz is an indicator of complete combustion, and monitoring the value can assure the proper portion of supplemental gas volumes to maximize combustion efficiency. EPA found that maintaining NHVcz above 270 Btu/scf (as calculated consistent with the requirements of Subpart CC) on a 15-minute average basis achieves a minimum control efficiency of 98% [80 Fed. Reg. at 75210]. Monitoring the dilution parameter ensures that degradation of performance for excess aeration does not occur [79 Fed. Reg. at 36907]. Visible emissions, when operating below the smokeless capacity of the flare, can be an indicator of improper operation of the flare or need for maintenance on the flare. Finally, operating with a proper flare tip velocity helps maintain the stability of the flame and prevents flame liftoff that can result in the release of uncombusted gases.

Suncor is subject to MACT CC when combusting regulated material, as defined in 40 CFR 63.641 (i.e., HAPs subject to control under MACT CC), at both the Plant 3 Flare and GBR Flare. Following the MACT CC flare monitoring requirements can assure that the flares comply with the VOC emissions limitations, which were based on emission factors that relied on the historic composition of flare waste gas and an assumed control efficiency of 98%. The monitoring scheme in MACT CC is relevant to the performance of the flare for VOC destruction, as EPA explains in its 2015 rule changes:

> In our revised analysis of the data, we analyzed all of the data together and determined the 270 Btu/scf NHVcz operating limit provided in the final rule would adequately ensure that flares achieve the desired 98-percent control efficiency regardless of the composition of gas sent to the flare. (80 FR 75216, December 1, 2015)

The MACT CC flare requirements are appropriate to rely on for a VOC emission limit that is based on 98% control efficiency since the HAP emissions expected to be emitted from the flare (e.g. hexane, benzene) are VOCs and because many of the 27 HAPs addressed in MACT CC are also VOCs. While VOCs are a larger class of pollutants than HAPs, it is the heat content, rather than the composition of the materials combusted that is more important in ensuring that those pollutants are destroyed in the flare.

That is, whether the gas composition is VOC or HAP a 98% control efficiency can be achieved for both pollutants when NHVcz is maintained above the indicator range. The other indicators similarly are not HAP-specific but provide an overall indicator of the flare's performance with an intent to achieve a 98-percent control efficiency regardless of the flare gas composition and in accordance with the requirements of Subpart CC.

EPA's Compliance Assurance Monitoring (CAM) Rule (40 CFR Part 64) indicates that, if a source relies on presumptively acceptable monitoring, no further justification for the appropriateness of that monitoring should be necessary other than an explanation of the applicability of such monitoring to the unit in question (40 CFR 64.4(b)). In accordance with § 64.4(b)(4), presumptively acceptable monitoring includes "[m]onitoring included for standards exempt from this part pursuant to § 64.2(b)(1)(i) or (vi) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant-specific emission unit."

The Division considers the monitoring design criteria in this CAM plan to qualify as presumptively acceptable monitoring under § 64.4(b)(4) because the emission standards in MACT CC are exempt from CAM requirements under § 64.2(b)(1)(i), both the Plant 3 Flare and the GBR Flares are subject to the flare monitoring requirements of MACT CC, the monitoring requirements in MACT CC are applicable to the performance of the flares for VOC destruction efficiency, and all relevant flare monitoring provisions of MACT CC have been included in this plan.

Excursions outside the indicator ranges cannot be directly correlated with an exceedance of the annual VOC emissions limitations for these flares. Exceedance is defined in § 64.1 as "… a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring." The monitoring in this CAM plan provides short-term data related to flare performance but does not provide data in terms of the emission limitation (tons per year, calculated on a rolling 12-month total), therefore, an excursion cannot be directly correlated with an exceedance of the VOC emissions limitations. Compliance with the emissions limitations for these flares is monitored according to the requirements of Conditions SECTION II - 30.1 and 31.1.

c.