Statement of Basis for the Air Operating Permit – Final

Phillips 66 Company
Ferndale Refinery

Ferndale, Washington

January 1, 2023

Serving Island, Skagit & Whatcom Counties

PERMIT INFORMATION

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SIC: 2911
NAICS: 324110
EPA AFS: 53-073-00005

NWCAA ID: 1004

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Table of Contents

Illustrations

Tables

Figures

1 Air Operating Permit

The Northwest Clean Air Agency (NWCAA) is issuing a facility air operating permit to the Phillips 66 Company Ferndale Refinery (Phillips 66) pursuant to Washington Administrative Code (WAC) 173-401 and NWCAA 322. Phillips 66 is a designated major source for the air operating permit program because the facility has the potential to emit more than 100 tons of particulate matter (PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur oxides (SO_X) and volatile organic compounds (VOCs), more than 25 tons per year of a combination of hazardous air pollutants (HAP), and more than 10 tons per year of an individual named single HAP. These air pollutants are defined as regulated air pollutants in Chapter 173-401 of the Washington Administrative Code (WAC).

The air operating permit is a compilation of all the air pollution requirements that apply to the refinery and are identified as applicable under WAC 173-401-200. The purpose of this Statement of Basis is to set forth the legal and factual basis for the Air Operating Permit and to provide background information on the facility. The Statement of Basis is not a legally enforceable document.

The NWCAA issued the original AOP #016 on May 20, 2003, with an expiration date of May 20, 2008. The AOP was renewed on January 1, 2011, with an expiration date of January 1, 2016, and the second renewal was issued on January 1, 2018, with an expiration date of January 1, 2023.

1.1 Permit Revisions in the third Renewal

The NWCAA received the application for the third AOP renewal on December 9, 2021. The following revisions have been made to the permit during this renewal.

Permit Information Page

- Updated the source contact information and general permit information on the permit information page.

Changes to Section 1 of AOP – Emission Unit Descriptions

Revised AOP Section 1 to reflect the current list of emission units and regulatory applicability.

- Updated OAC identification numbers
- Added “LSR” to Tier III heater identification
- Added Tier III/LSR unit number
- Updated descriptions of internal combustion engines
- Removed Tank 550x100 from Group 2 list and added to Group 1 list per OAC 1356

Changes to Section 2 of AOP – Standard Terms and Conditions

Revised AOP Section 2 to be consistent with current NWCAA format and content. Updated introduction test, citations, and dates.

- Revised Sections 2.4.5 Greenhouse Gas Reporting
- Added Section 2.8.7 for major stationary sources and major modifications in nonattainment areas
- Revised Section 2.9 Greenhouse Gas Regulation to reflect current state requirements

Changes to Section 3 of AOP – Standard Terms and Conditions for NSPS and NESHAP

In Section 3, introductory text was updated to be consistent with current NWCAA format and content. Updated standard terms & conditions for NSPS & NESHAP to NWCAA template language, delegation of NSPS/NESHAP to NWCAA Letters (dates) and updated citations (dates). Moved reference to and an explanation of NWCAA's ability to enforce federal regulations to the introductory text. Updated mailing information for notifications. Renumbered conditions.

40 CFR 60 NSPS

- Updated 3.1.3 Startup, Shutdown, Malfunction Record language.
- Updated 3.1.6 Performance Test language
- Updated 3.1.7 Test Method Performance Audit language
- Inserted Section 3.1.14 Recordkeeping and Reporting for 40 CFR 60 Subpart Kb

40 CFR 61 NESHAP

- Updated 3.2.8 Emission Tests language

40 CFR 63 NESHAP

- Excepted from 3.3.3 O&M for Part 63 NESHAP Sources - Subparts CC, UUU, ZZZZ & DDDDD. These subparts address O&M/general duty to operate and maintain affected source to minimize emissions specifically, and therefore, the requirements are included either as permit conditions in Section 4 (40 CFR 63 Subparts CC, UUU & ZZZZ) or in Section 6.5 (40 CFR 63 Subpart DDDDD).
- Removed 3.3.3.2 and 3.3.3.3 OMMP requirements because these requirements are now specifically cited in the requirement tables specific to the applicable affected sources (FCCU, CRU, SRU, Boilers and Heaters).
- Updated 3.3.7 Notification of Performance Test Language; added sections for modifications to the requirements by Subparts CC and UUU.
- Updated 3.3.8 Conduct of Performance Test language.
- Updated 3.3.9 Operation & Maintenance of Continuous Monitoring Systems language; added sections for modifications to the requirements by Subparts CC and UUU; identified exceptions for Subparts ZZZZ and DDDDD.
- Updated 3.3.10 Continuous Monitoring System Out of Control Periods to include an additional section with requirements specific to Subpart CC.
- Updated 3.3.11 Continuous Monitoring System Quality Control Program to note that as it applies to Subpart UUU, no written procedures are required for CMS and to add an additional section with requirements specific to Subpart CC.
- Updated 3.3.12 Continuous Monitoring System Data Reduction to add additional sections with requirements specific to Subparts CC and UUU, and a section for modifications to the requirements by Subpart ZZZZ.
- Updated 3.3.14 Notification to add an additional section with requirements specific to Subpart UUU; and noted exception for Subpart CC.
- Updated 3.3.15 Recordkeeping to add additional sections with requirements specific to Subparts CC and UUU; and noted exception for Subpart DDDDD.

- Updated 3.3.16 Startup, shutdown, & Malfunction Recordkeeping & Reports to remove requirements specific to SSMPs and affirmative defense provisions; noted that requirements do not apply to Subparts CC, ZZZZ and DDDDD; added requirements specific to Subpart UUU.
- Added 3.3.17 Reporting to reference periodic reports required under Subpart CC, reports required under Subpart UUU, and reports required under DDDDD for units designed to burn gas 1.
- Updated 3.3.18 Deviation Reporting to reference submittal of performance test reports electronically to EPA's Central Data Exchange.
- Updated 3.3.19 Recordkeeping Requirements for Sources with Continuous Monitoring Systems to remove requirements specific to SSMPs; added additional sections with requirements specific to Subparts CC & UUU; and noted exceptions for Subpart DDDDD.
- Updated 3.3.22 Notification of Compliance Status to add additional section for specific requirements for Subpart CC; and a section for modifications to the requirements by Subparts UUU and DDDDD.
- Removed 3.3.23 General Compliance Requirements for 40 CFR 63 Subpart ZZZZ, as these are specific requirements listed in Section 4.

Changes to Section 4 of AOP – Generally Applicable Requirements

Revised AOP Section 4 to be consistent with current NWCAA format and content. Updated introductory text. Moved reference to, and an explanation of, NWCAA's ability to enforce federal regulations to the introductory text. Clarified that monitoring, recordkeeping, and reporting (MR&R) requirements labeled "***Directly Enforceable***" are added under either NWCAA's "gap-filling" authority (WAC 173-401-615(1)(b) & (c)), or NWCAA's "sufficiency monitoring" authority (WAC 173-401-630(1)). Noted that MR&R requirements labeled as "CAM" are part of the Compliance Assurance Plan for the specified unit as required by 40 CFR 64.6(c) and that the CAM plan submitted by the facility is included in the Statement of Basis.

In the Generally Applicable Requirement table:

- Updated citation dates, as necessary. Included, where applicable, citations to NWCAA's "gap-filling" or "sufficiency monitoring" authority.
- Updated 4.1 MR&R list of reports.
- Removed 4.18 Ambient SO_2 Standards, consistent with changes to NWCAA regulations.
- Updated 4.27 language for Fenceline Monitoring for specificity and consistent with other refinery AOP terms.

Added the following terms and associated monitoring, recordkeeping, and reporting (MR&R) requirements:

4.31 – 40 CFR 63 Subpart CC Maintenance vent requirements

4.32 – 40 CFR 61 Subpart FF BWON

4.33 & 4.34 – 40 CFR 63 Subpart CC (Refinery MACT 1)

- Requirement that emission standards apply to affected sources at all times
- General duty to minimize emissions

4.35, 4.36 & 4.37 – 40 CFR 63 Subpart UUU (Refinery MACT 2)

- Requirement that non-opacity standards apply to affected sources at all times
- Requirement that opacity & visible emission standards apply to affected sources at all times
- General duty to minimize emissions

4.38 & 4.39 – 40 CFR 63 Subpart ZZZZ (RICE MACT)

- General duty to minimize emissions

Changes to Section 5 of AOP – Specifically Applicable Requirements

Revised AOP Section 5 to be consistent with current NWCAA format and content. Updated introductory text. Moved reference to, and an explanation of, NWCAA's ability to enforce federal regulations to the introductory text. Clarified that monitoring, recordkeeping, and reporting (MR&R) requirements labeled "***Directly Enforceable***" are added under either NWCAA's "gap-filling" authority (WAC 173-401-615(1)(b) & (c), or NWCAA's "sufficiency monitoring" authority (WAC 173-401-630(1)). Noted that MR&R requirements labeled as "CAM" are part of the Compliance Assurance Plan for the specified unit as required by 40 CFR 64.6(c) and that the CAM plan submitted by the facility is included in the Statement of Basis.

In the Specifically Applicable Requirement tables:

- Updated citation dates, as necessary. Included, where applicable, citations to NWCAA's "gap-filling" or "sufficiency monitoring" authority.
- Updated OAC 733e reference and date to current permit 733f issued on December 10, 2019.
- Updated OAC 1012d reference and date to current permit 1012e issued on May 24, 2018.
- Updated AOP term 5.2.37 to allow source testing of NH_3 at the Vacuum Flasher Heater (4F-2) during normal operating conditions as per the revised OAC 1012d issued May 24, 2018.
- Updated AOP term 5.5.14 to include NO_X emission limits and testing at the DHT heater as per the revised OAC 780b issued December 22, 2021.
- Revised 40 CFR 63 Subpart DDDDD permit terms to point to Section 6.7. Moved explicit 40 CFR 60 Subpart DDDDD permit terms for boilers and process heaters to Section 6.7. Revised tune-up requirements from no less than once every 61 months (5 years) to no less than every 13 months (annual) per P66 request letter dated February 4, 2019.
- Removed 40 CFR 63 Subpart UUU requirements for bypass lines at SRU #1 and SRU #2 requiring seals on bypass lines – bypass lines at the refinery do not meet the definition of bypass lines because the lines cannot discharge to atmosphere.
- Added AOP term 5.6.19 OAC 908c Condition 4 (8/20/2019) to provide greater SS&M flexibility at SRU #2. Revise AOP term 5.6.20 OAC 908c Condition 5 (8/20/2019) to allow more control options for the elemental sulfur sweep gas.
- Removed AOP terms 5.8.1 through 5.8.6 citing 40 CFR 60.18 and 63.11 as replaced by 40 CFR 63.670 after January 30, 2019, per applicability in 40 CFR 63.640. Phillips 66 must comply with AOP terms 5.8.7 through 5.8.11 citing 40 CFR 63.670.

- Revised AOP term 5.8.11 to include requirement to submit all revisions of the FMP to NWCAA for sufficiency monitoring. During the AOP renewal, NWCAA identified a need to maintain a copy of the current FMP at its office. The latest version of the document is needed for staff to review incidents reported by Phillips 66 for compliance with the FMP. NWCAA used its sufficiency monitoring authority to add this requirement to the AOP renewal.
- Revised AOP term 5.8.15 to include reporting monthly events when H_2S content of gases combusted in the flare exceed 162 ppm, 3-hr rolling average as required by 40 CFR 63.107a(i)(2).

Changes to Section 6 of AOP – Commonly Referenced Requirements

Revised AOP Section 6 to be consistent with current NWCAA format and content. Updated introductory text. Added heat exchangers in Section 6.6 to the list of equipment included in Section 6 but referenced in Section 5. Moved reference to, and an explanation of, NWCAA's ability to enforce federal regulations to the introductory text. Clarified that monitoring, recordkeeping & reporting (MR&R) requirements labeled "***Directly Enforceable***" are added under either NWCAA's "gap-filling" authority (WAC 173-401-615(1)(b) & (c)), or NWCAA's "sufficiency monitoring" authority (WAC 173-401-630(1)).

In the Commonly Referenced Requirement Tables themselves:

- Updated citation dates, as necessary. Included, where applicable, citations to NWCAA's "gap-filling" or "sufficiency monitoring" authority.
- Added Section 6.7 - 40 CFR 63 Subpart DDDDD – Boiler MACT as this applies to all boilers and process heaters at the refinery.

Changes to Section 7 of AOP - Inapplicable Requirements

- Included NWCAA 320 and 321 as both refer to registration requirements which apply to minor sources, not major sources.
- Included NWCAA 480 for clarity as it applies to solid fuel burning devices, which the refinery does not operate.
- Included WAC 173-400-100 through -104, for consistency with NWCAA 320-321, as both refer to minor source registration requirements.
- Included 40 CFR 60 Subpart RRR for clarity as the refinery does not have SOCMI process units onsite.
- Removed 40 CFR 63 Subpart XX – loading rack not subject to Subpart XX because of applicability date; however, 40 CFR 63 Subpart CC refers to Subpart R which refers to Subpart XX.
- Included 40 CFR 63 Subpart Y as the refinery marine loading does not exceed the 10 tons of individual or 25 tons of combined HAPs emissions at the dock.

2 Introduction and General Facility Description

2.1 Facility Description

Phillips 66 is located at 3901 Unick Road in Ferndale, Whatcom County, Washington. The refinery is situated on the coastline adjacent to the Strait of Georgia in a rural setting zoned for heavy industrial use (Figure 2.1). The refinery is located in an area that is in attainment with all National Ambient Air Quality Standards (NAAQS); however, the area due north, and adjacent to the refinery, is in nonattainment for the 2010 SO_2 NAAQS. The Phillips 66 refinery was excluded from the SO_2 nonattainment area as it does not non-significantly contribute to the SO_2 NAAQS exceedance.

Phillips 66 is a petroleum refinery refines feedstock as crude oil to a variety of petroleum products including gasoline, diesel, fuel oil, liquefied petroleum gas (LPG) and butane. The refinery receives crude oil via marine vessels, railcars, and by pipeline. The crude oil throughput capacity of the refinery is approximately 108,000 barrels per day.

Crude oil enters the refining process at the Crude Distillation Unit where hydrocarbon is separated into light and heavy fractions based on boiling points. These fractions or "cuts" are routed to other process units where they undergo catalytic cracking, catalytic reforming, isomerization, alkylation, or treatment. Treating systems are used to remove or reduce fuel impurities such as sulfur and benzene. Sulfur is recovered in the Sulfur Recovery Plant as elemental sulfur. Some of the lighter hydrocarbons are flashed off as gases during processing and used as fuel in the refinery's fuel gas systems. The refinery has an oily wastewater system that routes hydrocarbon contaminated wastewater to the refinery's wastewater treatment system prior to discharge into the Straits of Georgia. In final processing, fuel components are blended into finished products and stored for shipping to market via ship, barge, pipeline, railcar, or truck.

Figure 2-2-1 Phillips 66 Aerial View

Phillips 66 underwent major upgrades in 2003 and 2007. In 2003, the original Thermofor Catalytic Cracking Unit (TCCU) was replaced with a new Fluidized Catalytic Cracking Unit

(FCCU) improving refining efficiencies and reliability. The project included adding hydrocarbon desulfurization capacity allowing the refinery to produce low sulfur gasoline products, mandated by federal fuels standards. In 2007, the Crude Unit and FCCU Gas Plant were upgraded, and a second Sulfur Recovery Unit (SRU#2) was installed. In 2014, a railcar unloading facility was added. The Tier III Hydrotreater Unit began operation in 2019, allowing the refinery to produce gasoline meeting Federal Tier III standards.

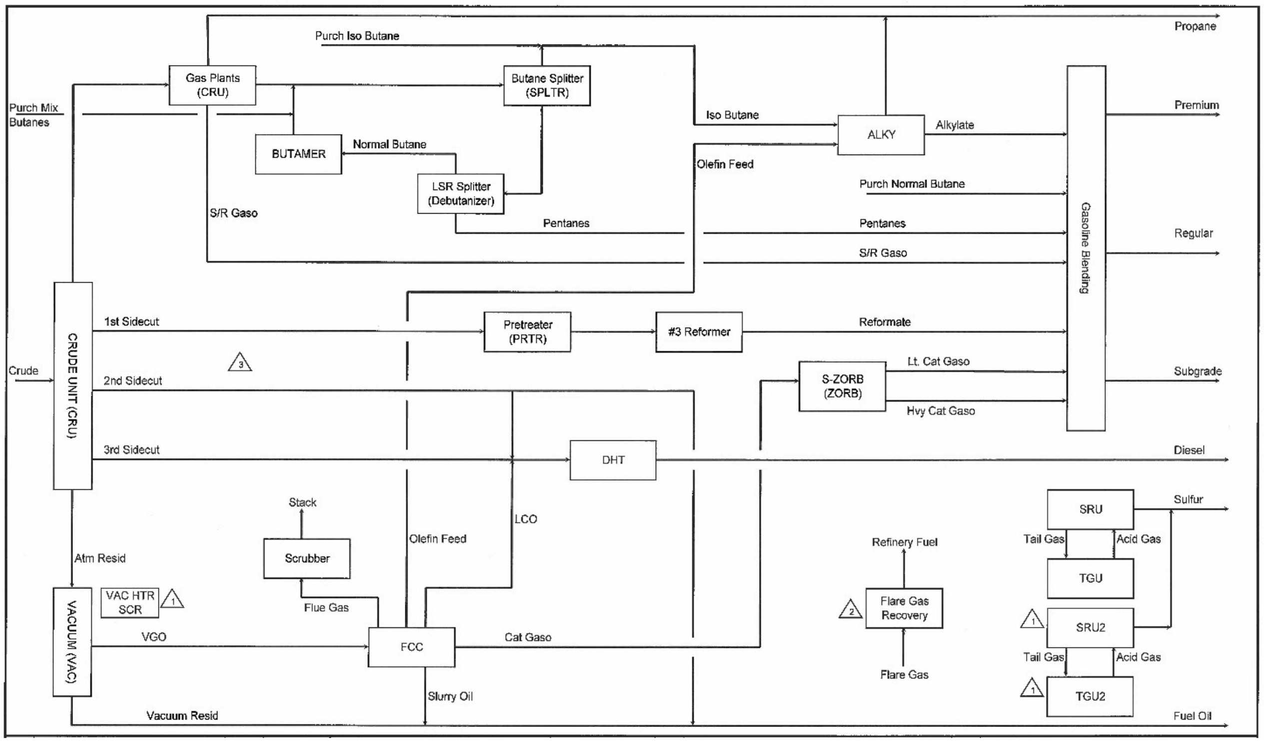

Figure 2-2-2 Phillips 66 Process Flow Diagram

A more detailed description of general petroleum refinery processes and the resulting air emissions may be found in Chapter 5 of EPA's publication AP-42, Compilation of Air Pollutant Emission Factors. The principal sources of air emissions from the refinery include:

- Combustion units including process heaters and boilers
- The Fluid Catalytic Cracking Unit (FCCU)
- Storage of hydrocarbons in tanks including crude oil, gasoline, and intermediates
- Fugitive emissions from leaking valves, pumps, and compressors
- The Sulfur Recovery Units (SRU #1 and #2)
- Oily wastewater conveyance and treatment at the effluent plant

2.2 Facility History

Phillips 66 was constructed in 1953 and 1954 by Mobil Oil Corporation. The BP Oil Company owned the refinery from 1988 to 1993. The Tosco Corporation owned the refinery from 1993 to 2001. Phillips 66 Company purchased the refinery in 2001. In 2002, Phillips 66 merged with Conoco to form ConocoPhillips, a fully integrated oil company with assets in extraction, refining and marketing. In 2012, ConocoPhillips spun off Phillips 66 Company as a new, stand-alone, global refining and marketing company. The Phillips 66 Company currently owns and operates the refinery.

Phillips 66 was originally designed to process low sulfur Canadian crude oil delivered by pipeline from Alberta. The original throughput capacity was approximately 35,000 barrels of crude oil per day. The facility was expanded in 1967, 1972, 1990, and 2007 to its current crude oil processing capacity of approximately 108,000 barrels per day. The major projects completed since original construction include:

- 1992 installation of the Diesel Hydrotreater Unit (DHT)
- 1996 replacement of #1 Boiler
- 1997 installation of the Butane Isomerization Unit for conversion of normal butane to isobutane at the Alkylation Unit
- 2000 installation of Merox Extraction Unit to remove mercaptans from olefin feed streams to the Alkylation Unit
- 2002 installation of a new debutanizer distillation tower in the Alkylation Unit
- 2003 installation of the Fluidized Catalytic Cracking Unit (FCCU) and Catalytic Gasoline Desulfurizer Unit (S-Zorb CGD)
- 2004 installation of #4 Boiler to replace temporary boiler
- 2007 installation of the #2 SRU and SCOT tail gas treating (TGU) with incinerator and economizer
- 2007 modification of the Crude Distillation Unit to reduce the benzene content of finished gasoline, complying with the USEPA's Mobile Source Air Toxic (MSAT) Phase 2 rule
- 2009 installation of Selective Catalytic Reduction (SCR) system on the Vacuum Flasher Heater to meet NO_X reduction obligations of the Consent Decree
- 2010 installation of an Enhanced Selective Non-Catalytic Reduction (ESNCR) system on the Carbon Monoxide Boiler (CO Boiler) to control NO_X emissions at the FCCU
- 2011 installation of a Flare Gas Recovery (FGR) system to meet requirements of the Consent Decree to reduce flaring
- 2012 installation of the ethanol truck unloading facility
- 2014 installation of the railcar facility for unloading crude oil
- 2015 replacement of the ZTOF flare with a new steam-assisted, elevated flare
- 2017 installation of the Hydrotreater Unit (Tier III/LSR) to remove sulfur from feedstocks, complying with the USEPA Tier III gasoline sulfur standards.

Numerous other smaller projects have been completed at the refinery and are identified within the associated process area descriptions in this Statement of Basis. Table 2-1 is a list of active Orders of Approval (OAC), Compliance Orders (CO), Consent Decree (CD) and Prevention of Significant Deterioration (PSD) permits included in the AOP. Any updates to the provisions of these Orders have been incorporated into this third AOP renewal. The OACs marked with asterisks are applicable to the listed equipment but have no ongoing requirements; therefore, these OACs are not included in the AOP Section 5 emission unit requirements.

Table 2-1 Active Permits Included in the AOP

Permit Issuance Date	Permit Number	Description	Startup Date	Supersedes
6/9/2016	265a	Truck loading rack – OAC cleanup.	Existing	265
10/2/2002	314a	Construct 3 tanks and retrofit 5	Existing	314
10/2/2002	564a	Isom Unit – OAC cleanup	Existing	564
6/9/2016	578b	Boiler #1 – OAC cleanup	Existing	571, 578a
6/9/2016	727a	Merox Extraction Unit – OAC cleanup	Existing	727
12/10/2019	733f	Ferndale Upgrade and Clean Fuels Project – provide SS&M flexibility for SRU #1	Existing	244, 288a, 681, 733e
12/22/2021	780b	Replace DHT heater burners with new ULNB	Existing	343, 552, 780a
6/9/2016	795a	Debutanizer distillation tower in Alkylation Unit – OAC cleanup	Existing	795
6/9/2016	877b	Boiler #4 – OAC cleanup	Existing	849, 877
8/20/2019	908c	Crude/FCC/Sulfur Recovery – high range analyzer, SS&M flexibility at SRU #2, control options for elemental sulfur sweep gas	Existing	908b
5/24/2018	1012e	Vacuum Flasher Heater – source testing under normal operations	Existing	340, 1012d
10/16/2008	1029	Construct Flare Gas Recovery System	5/14/2010	---
10/21/2014	1047a	CO Boiler – remove requirement to operate ENSCR at all times, adjust source test frequency	Existing	1047
2/16/2012	1111	Construct ethanol truck unloading facility	2/22/2013	---

Permit Issuance Date	Permit Number	Description	Startup Date	Supersedes
6/7/2013	1152	Construct facility to transfer crude from railcars to existing refinery storage	11/18/2014	---
3/7/2014	1174	Construct Flare infrastructure upgrade project	10/5/2015	---
10/23/2015	1223	Construct Tier III/LSR hydrotreater unit	1/10/2019	---
2/11/2016	1232	Replace existing Crude tower with new unit	3/27/2017	---
4/1/2019	1245*	Addition of process components at the DHT unit	9/19/2019	---
8/5/2019	1322	Construct crude oil storage tank and fuel oil storage tank	Not constructed – OAC invalid (NWCAA 300.11 (A))	---
10/5/2020	1356	Install Group 1 service seal on tank to allow flexibility to store higher vapor pressure material	2/15/2021	---
4/10/2014	CO-11	Enforceable order for terms of Consent Decree at the flares	4/10/2014	---
7/14/2014	CO-13	Enforceable order for CO limits at the FCCU	7/14/2014	---
1/27/2005	CD H-05-0258	Purposes of controlling air emission pollutants	1/27/2005	---
11/16/2005	PSD-05-01	Increase crude and FCCU feed, increase SRU removal capacity	11/16/2005	---
9/9/2015	PSD-00-02 Amd 8	Construct FCCU, S-Zorb, modify the Alkylation Unit, modify the #2 Hydrofiner, modify the SRU #1	12/10/2019	PSD-00-02 Amd 7

2.3 Enforcement History

Table 2-2 presents a list of formal enforcement actions taken against Phillips 66 since the last renewal in 2018. Each violation has been resolved through a combination of penalty assessments and corrective action taken by the source. In most cases a summary of corrective action taken by the source is submitted to the NWCAA as a written response to the violation. Additional information about each violation can be obtained upon request to the NWCAA.

Table 2-2 Notice of Violation History

Date Issued	NOV#	Summary	Penalty
9/10/2018	4301	Failure to perform a timely RATA during the first calendar quarter of 2018 at the elevated flare H_2S CEMS.	$4,000
10/22/2018	4308	Operational actions increased H_2S in the main refinery fuel gas system, exceeding the 162 ppm limit and resulting in approximately 323 pounds of excess SO_2.	$3,500
4/29/2019	4343	Performance testing conducted on October 4, 2018, found the DHT Heater operating at 0.06 lb NO_X per 3-hour average and greater than the BACT limit of 0.05 lb per 3-hour average.	$2,000
4/27/2020	4419	FCCU/CO Boiler stack emissions of 1,132 pounds CO caused by improper maintenance.	$2,000
8/21/2020	4428	Process upsets on 3/15/2020 and 5/11/2020 released excess SO_2 emissions at the SRU #2 of approximately 194 pounds and 1,594 pounds, respectively.	$4,000
12/9/2021	4535	Process unit shutdowns and startups caused excess emissions events on April 19, 2021, and June 11, 2021, resulting in approximately 100 lbs of SO_2 and 1,000 lbs of SO_2 and visible emissions from flaring, respectively.	$12,000

2.4 Periodic Reports

The refinery has various reporting requirements resulting from federal, state, and NWCAA regulations as well as Prevention of Significant Deterioration (PSD) permits and Orders of Approval to Construct (OACs). In addition to periodic reports the refinery has specific action-based notifications and onsite recordkeeping requirements. As with all recordkeeping, data supporting the reported information must be maintained for at least five years.

As required in AOP term 4.1, monthly, quarterly, semiannual, and annual reports are required to be submitted within 30 days of the close of the reporting period, with specific exceptions. This 30-day deadline had been added as "***Directly Enforceable***" under the agency's Title V gap-filling authority to ensure reporting consistency. Exceptions from the 30-day deadline are called out in term 4.1 including, but not limited to, annual emission reports, fenceline benzene monitoring reports and the annual BWON total annual benzene (TAB) report. These exceptions have longer submission deadlines due in part to the more complex nature of the reports. The directly enforceable 30-day deadline was selected because in accordance with WAC 173-401-615(3) deviations are due within 30 days of the end of the month.

In general, periodic reports are considered those regularly submitted that provide information on the compliance status of the facility during the reporting period. They often include emission rates or operating parameters that have corresponding permit limits. One-time only notices, such as initial startup notices or initial MACT compliance status notices are not considered periodic reports for the purpose of AOP term 4.1 because they do not occur on a regular frequency.

Monthly Reports: The monthly air reports include a wide range of data collected during the month. A large part of the monthly report comprises performance data on the continuous monitoring systems (CEMs), including the duration and nature of CEMs downtime, changes made to the CEMs, total operating time, and dates of CEMs audits and certifications. Another significant element of monthly reports is the disclosure of deviations from required monitoring and exceedance of emission limits.

Quarterly Reports: The refinery is required to submit quarterly reports under the following regulations:

40 CFR 60 Subpart Db requires reports of NO_X emissions at the refinery boilers and NO_X CEMs performance.

40 CFR 60 Subparts J and Ja require reports of PM, CO and SO_2 emissions from refinery units, flare root cause analyses and corrective actions.

40 CFR 60 Subpart QQQ requires reporting data and type of defect found in the Individual Drain Systems (IDS) along with any corrective actions.

40 CFR 61 Subpart FF requires certification that the refinery met all applicable BWON monitoring and recordkeeping requirements.

40 CFR 63 Subpart CC reports of fenceline monitoring, submitted quarterly via EPA's CEDRI electronic reporting system, include sampling periods and sampling results of benzene.

Semiannual Reports: The refinery is required to submit semiannual reports under the following regulations:

40 CFR 63 Subparts CC (MACT I) requires reporting of monitoring and recordkeeping at miscellaneous process vents, storage vessels, wastewater, equipment leaks, gasoline loading racks, heat exchangers, and fenceline monitoring.

40 CFR 63 Subpart UUU (MACT II) requires reporting of monitoring and recordkeeping at catalytic cracking units, reforming units, and sulfur recovery plants.

The leak detection and repair (LDAR) program (required under multiple regulations) also requires a semiannual report summarizing the number of leaking components found and the number not repaired in a timely manner, an explanation as to the reason for the delay of repair, any process unit shutdowns, and any revisions to the program since the initial report.

Annual Reports: The refinery is required to submit annual reports under the following regulations:

40 CFR 61 Subpart FF requires an annual report summarizing the total annual benzene quantity in each facility waste stream and if the waste stream is controlled for benzene. For uncontrolled streams, parameters are listed describing the uncontrolled streams and the benzene quantity in each stream. Additionally, the refinery is required to submit an annual report under 40 CFR 61 Subpart FF detailing results of annual monitoring of leaks per Method 21, summary of annual inspections of IDS and vacuum trucks.

40 CFR 63 Subpart DDDDD requires an annual compliance report summarizing tune-ups performed on subject boilers and heaters and post tune-up combustion analyses.

Compliance Certifications: All required monitoring reports must be certified by a responsible official of the truth, accuracy, and completeness of the reports. When an applicable requirement requires reporting more frequently than once every six months, the responsible official's certification need only be submitted in a semiannual report that specifically identifies all documents subject to the certification.

Also, the refinery is required to submit an annual compliance certification that lists each term of the AOP, the compliance status, whether the compliance was continuous or intermittent, and the methods used for determining the compliance status.

2.5 Emissions Inventory

Each year the refinery is required to submit an emissions inventory for the entire facility upon request of NWCAA (NWCAA 150.1) and WA Department of Ecology (WAC 173-400-105(1)). This report includes criteria air pollutants (carbon monoxide, nitrogen oxides, particulate matter, sulfur dioxide, and volatile organic compounds) and toxic air pollutants (TAPs). Inventory reports from the refinery are categorized into different source groups as well as for individual emission units. NWCAA publishes the emissions inventory data on the NWCAA website, and the WA Department of Ecology includes the data in a state-wide emissions inventory report submitted to EPA. In addition, a GHG annual inventory is submitted to the EPA and Ecology.

Tables 2-3 and 2-4 summarize the last five years of available emissions data reported by the refinery. In general, emission rates at the refinery vary from year to year depending on the slate of crude oils used as a feedstock, the types and amounts of products produced, modifications to process equipment and/or emission control devices, maintenance activities which occur that year, and to some extent, improvements in the methods used to calculate emissions. As defined by the EPA, the major source threshold for any air pollutant is 100 tpy and thresholds for HAP are 10 tpy for a single HAP or 25 tpy for any combination of HAPs.

Table 2-3 lists actual criteria pollutants, ammonia, and greenhouse gas (GHG) emissions. Table 2-4 lists all hazardous air pollutants (HAP) and toxic air pollutants (TAP) emitted at or above 10 ton per year at least once during that five-year period, as reported by the refinery in the annual emission inventory reports.

Table 2-3 Annual Air Emissions

Pollutant	Calendar Years Emissions (tons)				
	2016	2017	2018	2019	2020
PM_{10}	54	60	59	21	46
SO_2	45	38	43	36	33
NOx	769	674	691	706	596
VOC	854	972	862	891	784
CO	177	181	154	166	139
THAP[a]	65	151	68	63	46
NH_3	4	8	5	9	4
GHG[b]	767,043	748,775	798,061	843,697	801,159

[a] Sum of USEPA designated HAPs
[b] Reported as CO_2e, in units of metric tons

Table 2-4 Any Single Hazardous or Toxic Emission over 10 tpy Annually

Pollutant	Calendar Years Emissions (tons)				
	2016	2017	2018	2019	2020
Toluene[1,2]	13	31	17	12	11
n-Hexane[1,2]	24	63	23	25	12
Xylenes[1,2]	10	24	6	5	5
Benzene[1,2]	6	17	7	5	4

[1] Hazardous air pollutant (HAP)
[2] Toxic air pollutant (TAP), per Chapter 173-460 Washington Administrative Code (WAC)

2.6 Miscellaneous Non-Process Activities

There are several regulated activities that emit air pollutants not generated by refining processes. These include refinery laboratory services, asbestos removal, fire training, abrasive blasting, painting, gasoline dispensing and cutback asphalt paving. Asbestos removal occurs during the demolition or modification of buildings and piping that are likely to contain asbestos-containing materials such as insulation and tiles. The refinery is subject to federal, state, and NWCAA asbestos requirements. Fire training uses open burning for instruction of the refinery's emergency response personnel. Open burning activities are subject to state and NWCAA requirements. Abrasive blasting and painting occur during maintenance and repair activities of tanks and equipment at the refinery. These activities are subject to state and NWCAA regulations. Gasoline is dispensed from pumps for fueling the refinery's fleet of vehicles used onsite, regulated under NWCAA. Finally, cutback asphalt paving occurs from time to time at the refinery to repair road and other impermeable surfaces. The use of cutback asphalt is subject to NWCAA regulations.

2.7 Insignificant Emission Units

The refinery has emission units and activities determined to be insignificant under WAC 173-401-530, -532, and –533. In general, the emission units are considered insignificant because they have low emission rates or generate only fugitive emissions. The Generally Applicable requirements in Section 4 of the air operating permit apply to these units, although the testing, monitoring, recordkeeping, and reporting requirements do not apply. As specified in WAC 173-401-530(2)(a), no emission unit or activity subject to a federally enforceable requirement, other than generally applicable requirements of the state implementation plan may qualify as insignificant. The insignificant emission units and activities located at Phillips 66 are listed in Section 6 of this Statement of Basis.

3 Regulatory Applicability

This section of the Statement of Basis identifies and discusses specific regulatory applicability of a wide range of local, state, and federal programs and requirements. Tables 3.1 through 3.3 list federal requirements and relevant emission sources.

3.1 New Source Performance Standards (NSPS)

Federal New Source Performance Standards (NSPS) apply to the control of criteria air pollutants emitted from specific types of sources that have been constructed or modified after the applicability date for each rule. The NSPS rules are found in Title 40 Code of Federal Regulations (CFR) Part 60. Criteria air pollutants are those associated with national ambient air quality standards (NAAQS) including carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) as a precursor for ozone.

Phillips 66 is subject to a number of NSPS subparts and the general provisions under Subpart A. Subpart A contains procedural and other requirements that apply, when a specific subpart applies, unless noted otherwise.

The following table lists NSPS regulations that apply to Phillips 66. A more detailed description of each rule is provided in this section.

Table 3-1 40 CFR Part 60 New Source Performance Standards (NSPS)

Subpart	Affected Facility	Process Unit	Emission Unit ID	Comments
A	FCCU	FCCU	FCCU	General control device & work practice requirements.
	Flare	Flare	Flare and FGR	
Db	Combustion Units	Utilities	Boilers #1 and #4	#1: 162 MMBtu/hr, triggered at construction, OAC 578, 4/9/1996 #4: 164 MMBtu/hr, triggered at construction, OAC 877, 8/12/2004 Does not apply to the FCCU CO Boiler because of a federally enforceable limit in OAC 733f restricting the amount of natural gas firing
J	Fuel Gas Combustion Unit	Crude Oil Process Area	Crude Heater (1F-1) and Supplemental Crude Heater (1F-1A)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		FCCU	Regenerator, Combustion Air Heater and CO Boiler	Triggered with installation, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		FCCU	Vac Tower Htr (4F-2)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		Alkylation	Alky Htr (17F-1)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		Alkylation	S-Zorb Htr	Triggered with construction, obligation of Consent Decree as stated in OAC 733, 4/6/2001

Subpart	Affected Facility	Process Unit	Emission Unit ID	Comments
		Reformer	#3 Reformer Htrs (18F-21, 22, 23 & 24)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		Reformer	Pretreat Htr (18F-1)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		Reformer	Regen Htr (18F-26)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		Reformer	DHT (33F-1)	Triggered with upgrade, obligation of Consent Decree as stated in OAC 733, 4/6/2001
		Utilities	Boilers #1, #2 and #4	#1: 162 MMBtu/hr, triggered at construction, OAC 578, 4/9/1996 #2: 91 MMBtu/hr triggered at modification, obligation of Consent Decree as stated in OAC 733, 4/6/2001 #4: 164 MMBtu/hr, triggered at construction, OAC 877, 8/12/2004
	FCCU	FCCU	Catalyst Regenerator	Triggered NSPS J with installation, obligation of Consent Decree as stated in OAC 733, 4/6/2001
	Sulfur Recovery Plant	SRUs	SRU #1 & #2	These units triggered as Claus sulfur recovery plants Construction dates: SRU#1 obligation of Consent Decree as stated in OAC 733, 4/6/2001, SRU#2, OAC 908, 11/17/2005
	Transfer Terminals	Truck Loading	VCU	Triggered with construction, OAC 265, 6/9/2016
Ja	Fuel Gas Combustion Unit	Flare	Flare	Triggered Ja with construction of the flare system, OAC 1174, 3/7/2014
		Tier III/LSR	Tier III/LSR	Triggered with construction, OAC 1223, 10/23/2015
K	Storage Tanks	IFRs	TK 100x94, 100x99	Triggered at retrofit, OACs 161 and 196
Ka	Storage Tanks	EFR	Tk 6000x1	Triggered at construction
Kb	Wastewater Tanks	EFR	TK 900x1, -2, -3	Triggered by retrofit, OAC 314, 8/21/1991
		IFR	TK 300x40	
	Storage Tanks	EFR	TK 100x92, 100x95, 300x44,	Triggered by retrofits, OAC 314, 8/21/1991, OAC 715 12/3/1999
		IFR	TK 70x1, 100x98	Ethanol tank 70x1 triggered by construction OAC 1111, 2/16/2012

Subpart	Affected Facility	Process Unit	Emission Unit ID	Comments
VV[1]	Components at SOCMI process units in VOC service	Refinery-wide		Units subject to VV are excluded from Subpart GGG & GGGa.
GGG[1]	Components in VOC service (construction, reconstruction, or modification after 1/4/83, but on or before 11/7/06 - triggers for entire process unit)	FCCU		Triggered at construction, OAC 733, 4/6/2001
		Alky		Triggered at modification, OAC 733, 4/6/2001
		Isom		Triggered at modification, OAC 564a, 10/2/2002
		DHT		Triggered at modification, OAC 886, 3/3/2005
		Merox		Triggered at modification, OAC 727, 5/31/2000
		S-Zorb		Triggered at construction, OAC 733, 4/6/2001
		Units that have not triggered		#3 Reformer – construction in 1972 Sulfur Recovery Plant – construction in 1978
GGGa[1]	Components in VOC service (triggered after 11/7/06)	Crude		Triggered at modification, OAC 1109, 12/8/2011
		Tier III/LSR		Triggered at construction, OAC 1223, 10/23/2015
		Flare		Triggered at construction, OAC 1174, 3/7/2014
QQQ	Process Drains in VOC service	Alky		Triggered at modification, OAC 795, 2/4/2002
		Tier III/LSR		built in the location of the decommissioned #2 Hydrofiner (HDF). The oily wastewater drains at the HDF were subject to Subpart QQQ because they were constructed in 2003, after the May 4, 1987, applicability date of the rule. Oily wastewater from the Tier III Hydrotreater Unit utilizes these existing drains and similarly, be subject to Subpart QQQ.
		DHT		Triggered at construction in 1992
		Wastewater Conveyance		Drains constructed/modified after 1987
IIII	Compression Ignition Internal	Dock	Emergency Generator (10G-100)	New (manufactured after 4/1/06 & commenced construction after 7/11/05) engine subject to 40 CFR 60 Subpart IIII.

[1] "process unit" definition currently stayed so process unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. So storage tanks and loading racks are not part of a process unit and are not subject to LDAR requirements under NSPS VV, GGG, GGGa.

Subpart	Affected Facility	Process Unit	Emission Unit ID	Comments
	Combustion Engines	TEL area	Emergency Generator (24-GEN--0101)	
		ROC area	Emergency Generator (29-GEN-01)	New (manufactured after 4/1/06 & commenced constructed after 7/11/05), non-emergency (> 100 hr/yr) engine, rated at 500 hp.

3.1.1 40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Subpart Db establishes nitrogen oxide emission standards and associated requirements for boilers that were constructed, modified, or reconstructed after June 19, 1984, with a heat input capacity greater than 100 MMBtu/hour. The #1 Boilers (22F-1C) and #4 Boiler (22F-1E) at Phillips 66 are subject to Subpart Db. Both boilers are approved to combust refinery fuel gas. However, in actual practice the #4 Boiler is fired only on natural gas. #1 Boiler was originally approved to combust #2 distillate fuel as a backup fuel; however, dual-fuel burners were never installed, and the approval order was revised to remove the ability to combust #2 distillate fuel.

To comply with Subpart Db, the #1 and #4 Boilers are equipped with continuous emissions monitoring systems (CEMS) for NO_X. The boilers do not have duct burners and are not limited by a low annual capacity factor.

40 CFR 60 Subpart Db does not apply to the #2 and #3 Boilers because they were constructed prior to June 19, 1984 and have not been reconstructed or modified since that time. The FCCU CO Boiler is a steam generating unit that was constructed after June 19, 1984, however, it is not required to meet any of the emission standards of Subpart Db because it has a federally enforceable limit in OAC 733f restricting the amount of natural gas that can be used for auxiliary firing to less than 10% of its annual capacity.

3.1.2 40 CFR 60 Subpart J and Ja– Standards of Performance for Petroleum Refineries

NSPS Subpart J establishes particulate matter, sulfur dioxide and carbon monoxide emission limits and associated requirements for fluid catalytic cracking unit catalyst regenerators constructed or modified after June 11, 1973. Subpart J also establishes sulfur dioxide emission limits and requirements for fuel gas combustion devices constructed or modified after June 11, 1973, and Claus sulfur recovery plants constructed or modified after October 4, 1976 (except Claus plants of 20 long tons per day (LTD) or less). The fluid catalytic cracking unit (FCCU), two sulfur recovery units (SRUs) and fuel gas combustion devices at the refinery are subject to NSPS Subpart J because they were constructed after the June 11, 1973, Subpart J applicability date.

Subpart Ja establishes sulfur dioxide emission (SO_2) limits for fuel gas combustion devices and flares that are constructed, reconstructed, or modified after May 14, 2007. The Tier III Hydrotreater Charge Heater and Elevated Flare are both subject to Subpart Ja because they were constructed after May 14, 2007.

Unit applicability is discussed for each of these groups of sources below.

Fuel Gas Combustion Devices: For fuel gas combustion devices, Subpart J allows the refinery to monitor the H_2S in the fuel gas instead of monitoring stack SO_2 emissions. The refinery has elected to use the H_2S monitoring option for all subject heaters and boilers. The H_2S limit specified in Subpart J is 230 mg/dscm (0.10 gr/dscf) on a 3-hour average. This is equivalent to 162 ppmv H_2S. Because CEMS measure the concentration of H_2S by volume, the AOP lists the Subpart J H_2S limit as 162 ppmv, 3-hour average. The truck rack vapor combustor is subject to Subpart J because it is considered a fuel gas combustion device, the fuel gas being gasoline vapors generated at the truck rack and combusted in the vapor combustor.

Similar to Subpart J for fuel gas combustion devices, Subpart Ja allows the refinery to monitor the H_2S in the fuel gas instead of monitoring stack SO_2 emissions. The refinery has elected to use the H_2S fuel gas monitoring option for the Tier III Hydrotreater Charge Heater. Subpart Ja imposes two H_2S limits for fuel gas; 162 ppmv on a 3-hour average, and 60 ppmv on a 365-day rolling average with continuous compliance monitored using an H_2S CEMS. The elevated flare, constructed after May 14, 2007, is subject to the Subpart Ja emission limit in §60.102a(g)(1)(ii) limiting fuel gas to less than or equal to 162 ppm H_2S. *Process upset gas* and *fuel gas* that is released to the flare because of relief valve leakage or other emergency *malfunctions* are exempt from this limit; however, recordkeeping requirements in §60.107a(i)(2) require reporting of emissions greater than 162 ppm H_2S without exception.

Most of the refinery heaters and boilers were constructed prior to the June 11, 1973, applicability date of Subpart J. However, these heaters and boilers are subject to Subpart J as an obligation of the Consent Decree. This obligation is memorialized in OAC 733f which established a federally enforceable requirement to comply with Subpart J. Table 3-2 identifies combustion devices that are subject to Subpart J due to their construction date, those that are subject to Subpart J under OAC 733f, and those that triggered Subpart Ja due to construction dates.

Table 3-2 Combustion Devices Subject to Subpart J or Ja

Process Unit	Subpart J Direct	Subpart J via OAC 733f	Subpart Ja Direct
Crude Heater (1F-1)		X	
Supplemental Crude Heater (1F-1A)		X	
FCCU Combustion Air Heater (4F-100)	X	X	
Vacuum Flasher Heater (4F-2)		X	
Alkylation Depropanizer Reboiler (17F-1)		X	
Cat Gas Desulfurizer Feed Heater (38F-101)	X	X	
Tier III Hydrotreater Charge Heater (4F-1)			X
#3 Reformer Heater (18-F21-F22-F23-F24)		X	
#3 Reformer Pretreat Heater (18F-1)		X	
#3 Reformer Regenerator Heater (18F-26)		X	
Diesel Hydrotreater Heater (33F-1)	X	X	
#1 Boiler (22F-1C)	X	X	
#2 Boiler (22F-1A)		X	
#3 Boiler (22F-1B)		X	
#4 Boiler (22F-1E)	X	X	
Elevated Flare (13V-11)			X
Truck Rack Vapor Combustor	X		

Sulfur Recovery Units (SRUs): The refinery operates two SRUs – Unit #1 constructed in 1978 and Unit #2 constructed in 2007 – both subject to NSPS Subpart J SO_2 requirements.

Elevated Flare: The flare is subject to NSPS Ja, triggered by construction in 2015. Subpart Ja requires that flared gas be limited to 162 ppmv H_2S on a 3-hour average – see discussion above under Fuel Gas Combustion Devices.

Subpart Ja also requires that the refinery develop and implement a flare management plan, conduct a root cause analysis and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet per day (scf) above the baseline flow, or contains sulfur that upon combustion, will emit more than 500 pounds of SO_2 in a 24-hour period. In accordance with 60.103a(d)(3), if the SO_2 is emitted from flaring during a planned refinery startup or shutdown, the root cause analysis and corrective action analysis is not required but the discharge must be recorded and reported.

Fluid Catalytic Cracking Unit (FCCU): In 2003, the FCCU was constructed to replace the Thermofor (thermal) Catalytic Cracking Unit (TCCU), triggering NSPS Subpart J emission limits for CO, PM and SO_2 permitted under OAC 733. At the same time, the Washington Department of Ecology (Ecology) issued PSD-00-02 for NO_X, PM/PM_{10} and CO. Subsequent revisions to OAC 733 incorporated Consent Decree requirements.

3.1.3 40 CFR 60 Subpart K, Ka and Kb – Standards of Performance for Storage Vessels for Petroleum Liquids

Storage vessels at an existing source may trigger applicability of 40 CFR 60 Subparts K or Ka or Kb, depending on the date of construction and/or modification.

- 40 CFR 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978 (NSPS K)
- 40 CFR 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984 (NSPS Ka)
- 40 CFR 60 Subpart Kb: New Source Performance Standards for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (NSPS Kb).

A summary of NSPS applicability for storage tanks constructed or modified after June 11, 1973, is provided in Table 2-2.

Table 3-3 Storage Tanks Subject to Subparts K, Ka or Kb

Tank	Type[1]	Product	Subpart K	Subpart Ka	Subpart Kb	Trigger[2]
6000X1	EFR	Crude oil		X		Construction, 1978
900x1	EFR	Wastewater			X	Construction, 2002
900x2	EFR	Wastewater			X	Construction, 2002
900x3	EFR	Wastewater			X	Construction, 2002
400x1	IFR	Naphtha			X	Construction, 2000
300x40	IFR	Wastewater			X	Modification[3] 1991
100x94	IFR	Recovered oil	X			Modification[3], 1975
100x98	IFR	Recovered oil			X	Modification[3], 1991
100x99	IFR	Recovered oil	X			Modification[3], 1977
70X1	IFR	Ethanol			X	Construction, 2012

1. EFR = external floating roof, IFR = Internal floating roof.
2. Construction/modification date based on NSR (OAC) permitting date, except for Tank 6000X1 that was permitted in 1975 but constructed within the Subpart Ka applicability dates.
3. Modification involved converting from a fixed roof to an internal floating roof tank.

NSPS Subparts K, Ka, and Kb require specific equipment standards to control fugitive VOC emissions from tanks. It also includes inspection, testing, monitoring, recordkeeping, and reporting requirements to ensure compliance.

Because all the storage tanks at Phillips 66 subject to Subpart K, Ka, or Kb are considered MACT Group 1 tanks under 40 CFR 63 Subpart CC, the federal regulations only require the storage vessels to comply with 40 CFR 63 Subpart WW - National Emission Standards for Storage Vessels (Tanks) - Control Level 2, which is the compliance option selected by the refinery under §63.660 of Subpart CC (letter dated March 31, 2016). This option was added on December 15, 2015, the date revisions to 40 CFR 63 Subpart CC were promulgated under the refinery sector rule to address residual risk. A more detailed discussion of 40 CFR 63 requirements is in Section 3.2 NESHAP – Storage Vessels.

Tanks storing wastewater can be an exception. If a MACT Group 1 tank is storing wastewater that is considered a Group 1 wastewater stream under Subpart CC, the tank must comply with the requirements for storage tanks under 40 CFR 61 Subpart FF (BWON). Phillips 66 has elected to meet Subpart FF requirements for tanks under §61.351 - Alternative Standards for Tanks, that requires the following:

- An IFR tank must meet the equipment specifications of Subpart Kb §60.112b(a)(1).
- An EFR tank must meet the equipment specifications of Subpart Kb §60.112b(a)(2).

In summary, tanks at Phillips 66 that are subject to NSPS Subpart K, Ka, or Kb due to their construction or modification date are not required to comply with K, Ka, or Kb when they are considered a MACT Group 1 tank under Subpart CC, unless storing a Group 1 wastewater stream. If the tank is storing a Group 1 wastewater stream, it is also required to comply with the equipment standards of Subpart Kb. The following tanks at the refinery are MACT Group 1 tanks that store a Group 1 wastewater stream:

- EFR Tanks 900X1, 900X2, and 900X3
- IFR Tanks 300X40, 100X94, 100X98, and 100X99

Under NWCAA Regulation, all the tanks at the refinery that store high volatile organic liquids (VOL) must comply with the equipment and maintenance provisions of 40 CFR 60 Subpart Kb as specified by the SIP approved version of NWCAA 580.3 - High Vapor Pressure Volatile Organic Compound Storage Tanks. High VOL means liquids with a true vapor pressure greater than 1.5 psia.

The following tanks require compliance with 40 CFR 60 Subpart Kb as a condition of OAC 314a:

- EFR Tanks 100X92 and 100X95 to be retrofit with rim mounted continuous secondary seals conforming to the design requirements of 40 CFR 60 Subpart K §60.112b(a)(2).
- IFR Tanks 300x40 and 100x98 to be retrofit with internal floating roofs conforming to the design requirements of 40 CFR 60 Subpart Kb §60.112b(a) (1).

All four tanks meet the requirements of 40 CFR 60 Subpart Kb as follows; testing under §60.113b, recordkeeping and reporting under §60.115b, and vapor pressure monitoring of liquids under §60.116b.

The AOP includes the requirements of 40 CFR 60 Subpart Kb. However, the obligation to comply with Subpart Kb is not because the tank is subject to Subpart Kb directly. Instead, it is imposed through one or more of the following referring regulations or order; 40 CFR 61 Subpart FF (BWON), NWCAA 580 or OAC 314a.

OAC 1111 states that Tank 70x1 is subject to 40 CFR 60 Subpart Kb. This statement is found in a section of the OAC that is not enforceable. Instead, the requirement to comply with Subpart Kb is through direct applicability of Subpart Kb. Tank 70x1 is dedicated to storing ethanol that is used as a blending component in gasoline. Ethanol does not contain greater than 4% HAPs on an annual average and the tank is considered a Group 2 storage vessel under Refinery MACT Subpart CC. As a Group 2 tank, the refinery is required to comply with NSPS Subpart Kb for VOC control and is not provided the flexibility to comply with 40 CFR 63 Subpart WW instead of 40 CFR 60 Subpart Kb.

The AOP does not list the requirements of Subpart K or Ka because under the overlap provisions of Subpart CC, Group 1 tanks subject to Subpart K or Ka are only required to comply with the storage vessel provisions of 40 CFR 63 Subpart WW, the compliance option selected by the refinery. All the tanks constructed or modified under the time periods of Subpart K and Ka are considered Group 1 tanks under Subpart CC.

3.1.4 40 CFR 60 Subpart VV/VVa and GGG/GGGa – Standards of Performance for Storage Vessels for Petroleum Liquids

Fugitive VOC and HAP emissions occur at process units throughout the refinery from leaking equipment components and process equipment. Components may include pumps, valves, compressors, flanges, open-ended lines, and safety vents to the atmosphere. Process units at the refinery are periodically monitored for leaks. When leaks are identified, they are required to be repaired within the time deadline specified in the applicable requirement.

These leaks are required to be controlled through work practice standards that are commonly referred to as leak detection and repair (LDAR). There are three distinct LDAR programs at Phillips 66. Each program is based on one of two federal NSPS programs. Under the LDAR programs equipment components must be surveyed for leaks and the leaks repaired in a timely manner with some exceptions. The main difference between the three LDAR programs is the concentration level as measured by a monitoring instrument, that defines a leak. Lower leak definitions represent a more stringent LDAR program.

40 CFR 60 Subpart VV – Leaks are defined as:

- 10,000 ppm for all valves and pumps in gas/light liquid service
- 10,000 ppm for all connectors
- 10,000 ppm for all components in heavy light liquid service

This LDAR program is required for the control of VOC emissions under NSPS 40 CFR 60 Subpart GGG for process units that were constructed, reconstructed, or modified between January 5, 1983, and November 7, 2006. This is the LDAR program prescribed to control HAP emissions throughout the refinery under MACT 40 CFR 63 Subpart CC. In addition, it is the LDAR program prescribed by Section 580 of the NWCAA Regulation to control VOC emissions from areas with a primary feedstock that is butane or lighter.

Modified 40 CFR 60 Subpart VV – Leaks are defined as:

- 1,000 ppm for all valves gas/light liquid service
- 2,000 ppm for all pumps in gas/light liquid service
- 10,000 ppm for all connectors
- 10,000 ppm for all components in heavy light liquid service

This LDAR program is required for the control of VOC and TAP emissions as BACT at specific process units as prescribed by OACs issued to the refinery during new source review.

40 CFR 60 Subpart VVa – Leaks are defined as:

- 500 ppm for all valves gas/light liquid service
- 2,000 ppm for all pumps in gas/light liquid service
- 10,000 ppm for all connectors
- 10,000 ppm for all components in heavy light liquid service

This LDAR program is required for the control of VOC emissions under NSPS 40 CFR 60 Subpart GGGa for process units that were constructed, reconstructed, or modified after November 7, 2006. In accordance with 63.640(p), it is also the LDAR program that may be used to control HAP emissions under MACT 40 CFR 63 Subpart CC in lieu of 40 CFR 60 Subpart VV. In some cases, the LDAR program under Subpart GGGa/VVa has been relied upon as BACT for VOC and TAP emissions during new source review by the NWCAA.

40 CFR 63 Subpart CC (Refinery MACT 1) applies to fugitive emissions from leaking components and process equipment at a petroleum refinery that is a major source of HAPs containing or contacting one or more of the listed HAPs at or above 5 wt%. Subpart CC is discussed in more detail in Section 3.2 NESHAP.

All these LDAR programs allow for a relaxation of the monitoring frequency for valves if their leak rates are found to be low during instrument monitoring surveys. In addition, all the LDAR programs require control strategies for specific equipment. Compressors must use a dual seal system that employs a barrier fluid to capture and detect leaks. Pressure relief devices that do not vent to the atmosphere must vent to a close vent system and control device. Sampling connections must use a closed-purge closed-loop or must route to a closed-vent system and control device. Open-ended lines must be double blocked using valves, blinds, and caps. Pumps that employ dual seals and a barrier fluid are allowed an alternative monitoring strategy.

All LDAR programs have requirements to monitor pressure relief devices that release to the atmosphere within five days of release to ensure that the device has resealed. All pressure relief devices in HAP service at Phillips 66 are scheduled to be routed to a closed vent system and control device. However, at this time there are some that still vent to the atmosphere and this five-day monitoring provision for pressure relief devices is included in the AOP.

NWCAA 580.8 requires a LDAR program conducted in accordance with 40 CFR 60 Subpart GGG (which references 40 CFR 60 Subpart VV) for components handling VOC at process units and loading sites which utilize butane or lighter hydrocarbons as a primary feedstock and excludes components in refinery fuel gas service.

In the current version of the regulation (amended March 13, 1997), the affected process units include the truck loading rack and the LPG railcar loading rack. To reduce overlaps between NWCAA 580 and similar requirements under federal regulations the NWCAA adopted NWCAA 580.26, which exempts any petroleum refinery process unit, storage facility, or other operation subject to federal VOC or HAP standards from 580.3 through 580.10. As such, the loading racks would technically be exempt from NWCAA 580.8 because they are subject to other federal rules. However, NWCAA 580.26 is not in the SIP and, as such, is not federally enforceable. Therefore, in the AOP, the references to NWCAA 580.8 for those process units that are subject to other federal rules are dated only with the date of the version incorporated into the SIP regulation (i.e., December 13, 1989).

In addition, for those units subject to the LDAR requirements under 580.8, the AOP also calls out one item because it is considered more stringent than similar LDAR requirements of 40 CFR 60 Subparts GGG and VV. That is the requirement under NWCAA 580.846 to inspect relief vents that have opened to the atmosphere within 24 hours of venting. The federal regulation allows up to five days for the relief valve to be checked to ensure that it has reseated.

To monitor for leaks, surveys are conducted using an instrument that can meet the requirements of 40 CFR 60 Appendix A Method 21 (EPA Method 21). When leaks are found they must be repaired within 15 days unless a delay of repair is utilized because the repair is technically infeasible or would cause greater emissions than the leak itself. If a delay of repair is utilized, the repair must be accomplished prior process unit startup following the next maintenance shutdown.

Table 3.4 identifies each LDAR program at the refinery and the process unit or area where it is employed. The table also identifies the regulatory driver, i.e., the underlying basis for requiring that LDAR program.

Table 3-4 LDAR Program Regulatory Drivers

Process Area	LDAR Program			Pollutants
	Subpart VV (NSPS or MACT)	Modified Subpart VV (BACT)	Subpart VVa (NSPS or MACT)	
Primary Crude Oil Process Area				
Crude Unit (Crude)	CC		GGGa	VOC & HAP
Catalytic Cracking Process Area				
Fluid Catalytic Cracking Unit (FCC)	GGG & CC	OAC 733e OAC 1047a[1]		VOC & HAP
Alkylation Process Area				
Alkylation Unit (Alky Gas and HF)	580, GGG & CC	OAC 733e & OAC 795a		VOC & HAP
CGD/S-Zorb Unit (S-Zorb)	GGG & CC	OAC 733e		VOC & HAP
Butane Isomerization Unit (Butamer)	580, GGG, CC & OAC 564a			VOC, HAP & PERC (HAP)
Tier III Hydrotreater Processing Area				
Tier III Hydrotreater Unit	CC		GGGa	VOC & HAP
Reformer/Diesel Hydrotreater Process Area				
#3 Reformer Unit (Reformer)	CC			HAP
Diesel Hydrotreater Unit (DHT)	GGG, CC & OAC 886			VOC & HAP
Sulfur Plant/Treaters Process Area				
Sulfur Recovery Unit (SRU/Treaters)	CC			HAP
Merox Unit (Merox)	GGG & CC	OAC 727a		VOC & HAP
Utilities Area				
Boiler Plant (Boilers)	CC			HAP
Flare System				
Flare Gas Recovery Unit (FGRU)	CC		GGGa, OAC 1029	VOC & HAP
Storage & Transfer Areas				
Truck Loading Rack (LRAC)	580 & CC			VOC & HAP
LPG Railcar Loading Unit (LPGU)	580[2]			VOC
Railcar Unloading Facility (RUL)	CC		OAC 1152	VOC & HAP
Marine Terminal (Dock)	CC			HAP
Effluent Conveyance and Treatment				
Effluent Treatment Plant (WWTR)	CC			HAP
Storage Vessels				
Tank Farm (Offplot)	CC			HAP

1. OAC 1047a modifies Subpart VV with a 500 ppm leak definition for valves instead of a 1,000 ppm leak definition for valves prescribed under OAC 727a, OAC 733f & OAC 795a.

2. The NWCAA 580.8 LDAR requirements for the LPG Railcar Loading Unit are from the current version of the NWCAA Regulation, not the SIP version because there are no federal LDAR requirements at this unit that would

trigger the overlap provisions under NWCAA 580.26. Note: the SIP version of 580.8 includes 580.846 requiring PRD be monitored within 24 hours of releasing to the atmosphere that is more stringent than Subpart VV.

"GGG" means NSPS 40 CFR 60 Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006

"GGGa" means NSPS 40 CFR 60 Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

"CC" means Refinery MACT 1 40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

3.1.5 40 CFR 60 Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

Subpart QQQ applies to process wastewater collection, conveyance and treatment systems at petroleum refinery equipment constructed, modified, or reconstructed after May 4, 1987. Subpart QQQ requires drain systems, junction boxes, and sewer lines to control VOC emissions. The rule also requires controls on wastewater (effluent) treatment systems such as oil-water separators and closed vent systems and control devices used for VOC control.

There is considerable regulatory overlap between NSPS 40 CFR 60 Subpart QQQ, BWON 40 CFR 61 Subpart FF and Refinery MACT 40 CFR 63 Subpart CC. Where Subpart CC overlaps with Subpart QQQ, Subpart CC takes precedence as provided in §63.640(o). This occurs when the equipment in effluent service is either managed as having, or services a Group 1 wastewater stream as defined in §63.461:

> *Group 1 wastewater stream* means a wastewater stream at a petroleum refinery with a total annual benzene loading of 10 megagrams per year or greater as calculated according to the procedures in 40 CFR §61.342 of Subpart FF of part 61 that has a flow rate of 0.02 liters per minute or greater, a benzene concentration of 10 parts per million by weight or greater, and is not exempt from control requirements under the provisions of 40 CFR 61 Subpart FF.

The equipment at Phillips 66 subject to the requirements of Subpart QQQ without a clear overlap provision are located at the Alkylation, DHT, and the Tier III Hydrotreater process units. The subject equipment includes individual drain systems, junction boxes, and sewers lines. The VOC control requirements of Subpart QQQ are included in Section 6 of the AOP. Whereas Section 5 of the AOP includes a reference to the Section 6 terms for the Alkylation, DHT, and the Tier III Hydrotreater units.

3.1.6 40 CFR 60 Subpart IIII – Standards of Performance for Stationary compression Ignition Internal Combustion Engines

40 CFR 60 Subpart IIII was promulgated in June 2006 applying NSPS standards to stationary compression ignition (CI) and reciprocating internal combustion engines (RICE). The rule was amended in June 2011, only applying to CI engines constructed on or after July 11, 2005.

The following CI engines are located at Phillips 66. All are diesel-fired and in dedicated emergency service. No stationary, spark ignition engines at the refinery are subject to the corresponding NSPS 40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

Table 3-5 Engines Subject to 40 CFR 60 Subpart IIII

Make and Model	Year	Brake Horsepower (hp)	Emergency Service
Emergency, CI Engines ≤ 500 hp, constructed before July 11, 2005 (NOT subject to 40 CFR 60 Subpart IIII)			
Detroit Model 62402RA	1953	264 hp	firewater pump
Detroit Model 62402RA	1953	264 hp	firewater pump
Detroit Model 62402RA	1953	264 hp	firewater pump
Kohler Model 20R0274	1986	61 hp	electrical generator
Emergency, CI Engines ≤ 500 hp, constructed on or after July 11, 2005 (subject to Subpart 40 CFR 60 Subpart IIII)			
Cummins Model QSB5-63 NR3	2009	132 hp	electrical generator
Kubota Model C2203-EBG	2008	33 hp	electrical generator
Caterpillar Model C9	2007	398 hp	electrical generator
Emergency, CI Engines > 500 hp, constructed before July 11, 2005 (NOT subject to 40 CFR 60 Subpart IIII)			
Caterpillar Model 3456	Nov. 2002	800 hp	electrical generator
Cummins Model K11A19G2)	1991	750 hp	electrical generator
Cummins Model VT-1710-F	1953	685 hp	firewater pump
Caterpillar Model 3412	2004	739 hp	firewater pump
Emergency, CI Engines > 500 hp, constructed on or after July 11, 2005 (subject to 40 CFR 60 Subpart IIII)			
None			

There are three CI engines that were constructed on or after July 11, 2005, subject to Subpart IIII. All are in dedicated emergency service and regulated in the ≤ 500 hp size category. None of these emergency generator engines are contractually obligated to be available for more than 15 hours per calendar year for emergency demand response as specified in §60.4211(f), for assisting in voltage/frequency deviations or for non-emergency situations to supply power as part of a financial arrangement with another entity.

To remain in the emergency use category under Subpart IIII, §60.4211(f)(2) limits the number of hours per calendar year in non-emergency service to 100 hours if it is used for the recommended maintenance checks and readiness testing. There is no limit to the number of hours an engine can run while in emergency service.

The three CI engines subject to Subpart IIII are required to be maintained in a manner that ensures they meet Tier 3 emission standards for nonroad engines. This includes conducting proper maintenance and not tampering with emission related settings on the engine that could compromise the emission standard. Subpart IIII also prescribes the type of diesel fuel that can be used in the engine. The engines subject to the Subpart IIII requirements of this subpart are listed in Section 5 of the AOP.

3.2 National Emission Standards for Hazardous Air Pollutants (NESHAP)

The National Emission Standards for Hazardous Air Pollutants (NESHAP) are found in Title 40 CFR Parts 61 and 63 and apply to the emissions of hazardous air pollutants (HAPs), by industrial source category, for the 187 HAPs specified by Congress. These rules apply to existing sources regardless of the construction/modification dates. The NESHAPs include a Subpart A with procedural and other requirements that apply generically to all the NESHAP subparts.

3.2.1 40 CFR 61 Subpart FF – National Emission Standards for Benzene Waste Operations (BWON)

40 CFR 61 Subpart FF, commonly referred to as benzene waste operations NESHAP (BWON), applies at petroleum refineries with more than 10 Mg per year of benzene in the waste streams. Along with general overall program standards, Subpart FF includes specific equipment standards including those for tanks, surface impoundments, containers, individual drain systems, oil-water separators, treatment processes, and closed-vent systems and control devices. The Refinery MACT 1 wastewater provisions include the same applicability criteria for Subpart CC Group 1 wastewater stream as those in Subpart FF. In effect, all the equipment subject to Subpart FF are also subject to Subpart CC. The list of wastewater streams subject to Subpart FF is substantial and varies from year to year. The refinery takes periodic samples and keeps records detailing the status of the various benzene containing waste streams at the facility, and whether they are controlled or uncontrolled. By no later than April 7th each year the refinery reports their total annual benzene (TAB). The report is based on each calendar year of BWON operations.

3.2.2 40 CFR 63 National Emission Standards for Hazardous Air Pollutants (NESHAP)

When a Part 63 NESHAP standard applies to a facility, the general provisions of 40 CFR 63 Subpart A also apply. These general provisions are included in Section 3 of the air operating permit. Subpart A requirements tend to be applicable only when triggered by a particular action, such an initial startup notice and an initial notification when a facility becomes subject to a standard under 40 CFR 63.

Table 3-6 40 CFR 63 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart	Affected Facility	Process Unit	Emission Unit ID	Discussion
CC	Misc. Process Vents	FCCU	Group 1 (25-FV-007) Group 2 (5K-1 and 5K-2)	Triggered due to HAP content > 20 ppm
		Alky	Group 1 (17HC-1717)	
		#3 Reformer	Group 1 - RBV Body Vents, Reactor Shroud Vents, Reactor Dump Nozzle Vent)	
		DHT	Group 1 – sour water drain drum flash gas vent (33C-40)	

Subpart	Affected Facility	Process Unit	Emission Unit ID	Discussion
	Maintenance Vents	Refinery-wide		For relief within each unit during SU/SD/Maintenance, or during inspection when equipment is emptied, depressurized, degassed, or placed into service. Part of Residual Risk & Technology Review.
	Loading Racks	Marine	Gas/Diesel Truck Loading Rack (LR-1)	Submerged loading required under Subpart CC. Annual loading capacity limited by OAC 733
	Vapor Combustor	Truck Loading	Vapor Combustion Device (11V-1)	Considered a thermal oxidizer
	Flares	Refinery-wide	Closed Vent Systems Routed to Flares	Process Vents and Pressure Relief Devices refinery-wide
	Wastewater Tanks	Group 1	EFR: 900x1, -2, -3, 300x35, 300x46	By definition, wastewater tanks not storage tanks - overlap provisions with NSPS (i.e., K, Ka, Kb) don't apply to wastewater tanks.
			IFR: 300x40, 100x94, 100x95, 100x98	
	Storage Tanks (see Table 3-8 for detailed discussion)	Group 1	External and floating roof	Storing high VP liquids with HAPs
		Group 2	IFR: 70x1 Ethanol	<4% HAPs triggers Group 2, overlap provision with Subpart Kb
			Fixed roofs tanks and one internal floating roof tank	Storing low VP and not in HAP service
	Refinery	Refinery Fenceline		Required by Residual Risk & Technology Review
	Heat Exchangers in HAP service	Cooling Towers	Cooling Tower #1	#1 handles water from the refinery except for the Alkylation Unit
			Cooling Tower #2	#2 handles water from the Alkylation Unit only
	Process Drains in HAP service	Group 1	FGR; EP	Process drains refinery-wide subject to CC
		Group 2	Refinery-wide	
	Components in HAP service (existing refinery that is a major source of HAP = streams with > 5% listed HAP by wt	Crude		#3 Reformer does not have components in HAP service. Diesel Railcar Loading Rack not subject - does not contain/contact material w/ 5% wt HAP.
		FCCU		
		Alky		
		S-Zorb		
		Isom		

Subpart	Affected Facility	Process Unit	Emission Unit ID	Discussion
		Tier III/LSR		
		#3 Reformer		
		DHT		
		SRUs		
		Flare and FGR		
		Truck Loading		
		Tank Farm		
UUU	CCUs	FCCU	Catalyst Regenerator Vent	At a petroleum refinery that is a major source of HAPs (em limit for CO from NSPS J as a surrogate for HAP & em limit for PM thru coke burn-off & VE from NSPS J as a surrogate for metal HAP)
	SRUs	SRU	SRU #1	Applies except §63.1569 requirements for HAP emissions from bypass lines. Phillips 66 does not have bypass lines that meet the definition in the rule – the lines are not piped to atmosphere.
			SRU #2	
	CRU	#3 Reformer	Catalyst Regenerator Drum Vent	Organic HAP emissions during depressurizing & purging of the CRUs to be controlled by purging the unit to the flare that meets 63670. Inorganic HAP emissions as HCl during coke burn-off & catalyst regeneration must be reduced to 30 ppmvd, @ 3% oxygen. Part of Residual Risk & Technology Review.
ZZZZ	ICE	Dock	Emergency generator (10G-100)	New (constructed after 6/12/06) emergency engines located at a major source of HAPs, rated at < 500 hp - per 63.6590(c), subject to 40 CFR 60 Subpart IIII also
		TEL area	Emergency Generator (24-GEN-0101)	
		ROC area	Emergency Generator (29-GEN-01)	
		Alky Unit	Emergency Generator (24GEN-0103)	Existing (installed prior to 6/12/06) located at a major source of HAPs, rated at > 500 hp. No requirements beyond initial notification.
		WWTP	Emergency Generator (12-GCP-2701)	
		Cooling Tower	Firewater Pump (29GV-09)	
		Utilities	Firewater Pump (21GV-301)	New (constructed after 6/12/06) emergency engines located at a major source of HAPs, rated at > 500 hp. No requirements beyond initial notification.

Subpart	Affected Facility	Process Unit	Emission Unit ID	Discussion
		Beach	Firewater Pump (26-GV-4)	Existing (installed prior to 6/12/06) located at a major source of HAPs, rated at > 500 hp.
			Firewater Pump (26-GV-5	
			Firewater Pump (26-GV-6)	
			Emergency Generator (22-GEN-0164)	
DDDDD	Boilers	Utilities	Boilers 1-4	All the boilers and process heaters subject to Subpart DDDDD are fired exclusively on natural gas and/or refinery fuel gas and fall under the category "units designed to burn gas 1 fuels". CO Boilers are subject to 40 CFR 63 Subpart UUU, so not subject per 63.7491(h).
	Process Heaters ICE	Crude	Crude Heater (1F-1)	
			Supplemental Crude Heater (1F-1A)	
		FCCU	Vac Flasher Heater (4F-2)	
		Alky	Alky Depropanizer (17F-1)	
			S-Zorb (38F-100)	
		Tier III/LSR	Tier III/LSR (41F-1)	
		#3 Reformer	#3 Reformer Heater passes 1 & 2 (18F-21 & 18F-22)	
			#3 Reformer Heater passes 3 & 4 (18F-23 & 24)	
			Pretreater Heater (18F-1)	
			Catalyst Regen Heater (18F-26)	
PPPPP		Refinery Lab	Engine Test Stand (3 engines)	Existing octane test engines (installed prior to 5/14/02) subject to PPPPP, but don't have to meet requirements of PPPPP. These units are not subject to ZZZZ

Refer to Section 4 for a more detailed discussion of each process and associated emission units.

3.2.2.1 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (aka Refinery MACT 1)

40 CFR 63 Subpart CC (commonly referred to as Refinery MACT 1) was originally published August 18, 1995. It applies to petroleum refining process units, and to related emission points located at a major source, that emit, contact, or have equipment that contact one or more HAPs listed in the NESHAP at or above 5 wt%. Refinery MACT 1 requires HAP emissions be controlled from various emission points within the refinery.

The affected source at Phillips 66 is comprised of all the emission points in combination listed below:

- Miscellaneous process vents (MPVs)
- Wastewater streams and treatment operations
- Equipment leaks from petroleum refining process units
- Gasoline loading racks
- Marine tank vessel loading
- Heat exchanger systems

Refinery MACT 1 was amended under the Refinery Sector Risk and Technology Review (RTR) initiative on December 1, 2015. Amendments followed based on petitions for reconsideration received by EPA, resulting in revisions finalized July 13, 2016, November 26, 2018, and most recently, February 4, 2020. The RTR-amended Refinery MACT 1 resulted in the following changes to the affected source at the refinery:

- Addition of a fenceline benzene monitoring program
- Removal of the requirement for startup, shutdown, and malfunction plans
- Upgrades to monitoring equipment (CPMS) for flares used as control devices
- Addition of requirements for pressure relief devices (PRD) routed to a closed vent system
- Revision of the definition of Group 1 miscellaneous process vents (MPVs)
- Addition of requirements for Group 1 MPVs and a category of maintenance vents that release to atmosphere
- Revision of the definition of Group 1 storage vessels
- Addition of tank fitting control requirements for Group 1 storage vessels, 40 CFR 63 Subpart WW – Tanks Control Level 2

All the Subpart CC requirements, including changes resulting from amendments to the Refinery MACT 1 have been incorporated with the following exceptions:

- During the 2017 maintenance turnaround at Phillips 66, all process vents in HAP service that had vented to the atmosphere were reconfigured to vent into the refinery flare gas header where they are recovered or controlled at the flare. Therefore, the provision for monitoring process vents that release to the atmosphere are not included in the AOP.
- The new definitions of Group 1 miscellaneous process vents and Group 1 storage vessel did not add any equipment to the list of process vents and storage vessels that were already in the AOP.

Equipment exempt from the affected source subject to Refinery MACT 1 include catalytic cracking unit vents, catalytic reformer catalyst regeneration vents, sulfur plant vents and emission points routed to the fuel gas system, provided that after January 30, 2019, any flares receiving gas from the fuel gas system are subject to the flare control requirements in §63.670. Other than the emission points routed to a fuel gas system, this equipment is addressed in 40 CFR 63 Subpart UUU, commonly referred to as Refinery MACT 2.

Some of the emissions units regulated under Refinery MACT 1 may be subject to other existing regulations including NSPS and other NESHAPs. Promulgation of Refinery MACT 1 provided for streamlining these applicable rules, and generally allows the source to demonstrate compliance by complying with only the most stringent standard. Following is an applicability discussion for process units or emission points at Phillips 66 subject to 40

CFR 63 Subpart CC. In addition, if the process/emission units are subject to requirements from other standards that overlap with requirements under 40 CFR 63 Subpart CC (see identification in Table 2-5), applicability of each regulation will also be discussed to clarify which provisions apply to the specific process, process unit or equipment.

Table 3-7 Areas with Overlapping Standards

Equipment	40 CFR 63	40 CFR 60	40 CFR 61	NWCAA Reg.
Storage Vessels/Tanks (including wastewater tanks)	Subpart CC	Subparts K, Ka, Kb	Subpart FF	560, 580.3, 580.9
Wastewater	Subpart CC	Subpart QQQ	Subpart FF	--
Equipment Leaks	Subpart CC	VV, VVa, GGG, GGGa	--	580.8

Miscellaneous Process Vents: For Miscellaneous Process Vents (MPVs) there are no other existing regulations governing Group 1 and Group 2 categories. As a result, all Group 1 and Group 2 process vents must comply with the requirements of Subpart CC. Note that the HAP-content applicability threshold for MPVs is 20 ppm. Phillips 66 maintains the following Group 1 MPVs:

- FCCU vented to flare gas header (25-FV-007)
- Alkylation Unit manual vent on olefin feed surge drum (17HC-1717)
- #3 Reformer RBV body vents, reactor shroud vents and Reactor dump nozzle vent
- DHT sour water drain drum flash gas vent (33C-40)

Group 1 MPVs are MPVs for which the total organic HAP concentration is greater than or equal to 20 ppmv, and the total VOC emissions at the outlet of the final recovery device (if any) and prior to any control device and prior to discharge to the atmosphere are greater than or equal to:

- 33 kg/day for existing sources, and
- 6.8 kg/day for new sources

Group 2 MPVs are any MPV that does not meet the definition of a Group 1 MVP. Changes resulting from the RTR further defined MPVs to include in-situ sampling systems (i.e., on-stream analyzers). All MPVs are routed to a flare that meets the control requirements of §63.670, therefore there were no changes required at any Group 1 MPVs for compliance with the amended RTR provisions

Maintenance Vents: Maintenance vents were designated as a special category of MPVs as part of the RTR initiative with newly required operational standards. The refinery has implemented procedures to identify all maintenance vents as they are used to provide relief within the unit as a result of startup, shutdown, maintenance, or for inspection of equipment when emptied, depressurized, degassed, or placed into service. Operational standards are in place to measure, record and ensure each maintenance vent LEL is below 10% prior to release to atmosphere. Because these vents can be found in every process unit at the refinery, there is no specific list identifying them, and Phillips 66 complies by following standard operating procedures for all maintenance vents. Since these vents are found facility-wide, requirements for maintenance vents are listed in the AOP in Section 4, under Generally Applicable Requirements.

Pressure Relief Devices (PRD): Refinery MACT 1 requires controls and additional monitoring of the control device for all PRDs routed to a closed vent system, which at Phillips 66 are routed to the refinery flare system.

For PRDs that are released to atmosphere (a.k.a. atmospheric PRDs), Refinery MACT 1 requires operating and pressure relief requirements and management of releases. These requirements are listed for these specific types of PRDs within the requirement tables in the AOP for the individual process units.

Elevated Flare: Flares used as control devices for emission points subject to this subpart are regulated under Refinery MACT 1. As the flare is used to control emissions from process vents and pressure relief devices within the refinery, the refinery flare system is subject to the control and CPMS requirements contained in Refinery MACT 1 §63.670 and §63.671, respectively, in addition to the flare requirements in NSPS Ja. Per the overlap provisions for flares in §63.640(s), flares subject to the provisions of either §60.18 or §63.11 in addition to Refinery MACT 1 are now only required to comply with the provisions specified in 40 CFR 63 Subpart CC.

Fenceline Benzene Monitoring: The RTR rule requires refineries to measure benzene emissions along the refinery perimeter. To meet this requirement, Phillips 66 operates 18 sampling stations along the refinery's perimeter, in addition to a field blank and a duplicate sampler. Each sampler continuously pulls ambient air through a passive diffuser tube for two weeks, after which the tubes are changed. Benzene concentration for each two-week period from each sampler is reported to EPA on a quarterly basis. The lowest individual monitor reading is subtracted from the highest individual monitor reading for each two-week period to determine the benzene concentration difference (Δc). An annual rolling average Δc is calculated every two weeks from the most recent 26 two-week sampling periods. If the annual rolling average Δc exceeds the benzene action level (9 $\mu g/m^3$), the refinery must perform a root cause and corrective action analysis; it does not constitute a violation of Refinery MACT 1. Because the fenceline benzene monitoring program applies facility-wide and is not associated with any individual processing unit, requirements are listed in the AOP in Section 4, under Generally Applicable Requirements.

Gasoline Loading Truck Rack: The gasoline loading rack at the refinery is a Group 1 affected source under Refinery MACT 1. The truck rack was constructed in 1953 and modified in 1990; therefore, not constructed/reconstructed/modified during the applicability date for 40 CFR 60 Subpart XX: Standards of Performance for Bulk Gasoline Terminals.

Marine Vessel Loading: Marine vessel loading operations are subject to 40 CFR 63 Subpart CC if they are located at a major source of HAPs, have equipment that contains or contacts one or more of the listed HAPs, and meet the applicability criteria under Subpart Y (63.560). The terminal at Phillips 66 is as it is an existing source and not a major source of HAP so not subject to Subpart Y; therefore, it is not subject to Subpart CC.

Heat Exchangers: As part of addressing residual risk, EPA promulgated requirements addressing HAP emissions from heat exchanger leaks at refineries in 40 CFR 63 Subpart CC on June 30, 2010, and published amendments on June 20, 3013. The regulation includes monitoring requirements with leak definitions and repair scheduling obligations for both closed-loop and once-through systems.

The subject heat exchangers must be "in organic HAP service" which is defined as having at least 5 wt% of listed HAPs. In addition, there are two exemptions: exchangers where the minimum pressure on the cooling water side is at least 35 kPa (~5.1 psia) greater than the maximum pressure on the process side and exchangers that employ an intervening cooling fluid that has less than 5 wt% HAP that is not sent to a cooling tower or discharged, which essentially isolates the cooling water from the process fluid. At this writing, the refinery has approximately 106 exchangers subject to Subpart CC and approximately 594 that are exempt. The subject heat exchangers are divided into two heat exchange systems, one for each refinery cooling tower. The cooling towers are monitored monthly with a leak action level of 6.2 ppmv.

Storage Vessels: Storage vessels at an existing source may trigger applicability for 40 CFR 60 Subparts K, Ka, and Kb, and NWCAA Regulations. The tanks may also trigger applicability under Refinery MACT 1 when they are associated with petroleum refinery process units that contact one or more listed HAPs.

Under Refinery MACT 1, subject storage vessels are divided into Group 1 and Group 2. Revisions promulgated to Refinery MACT 1 by EPA on December 15, 2015, included changes to the definitions of, and requirements for, Group 1 storage vessels.

After February 1, 2016, existing Group 1 storage vessels are now defined to have either:

- Design capacity greater than 151 m^3 (40,000 gal), a stored liquid maximum true vapor pressure of 5.2 kPa (0.75 psia), and an annual average HAP liquid concentration greater than 4 weight percent (%), or
- Design capacity greater than 76 m^3 (20,000 gal) but less than 151 m^3 (40,000 gal), a stored liquid maximum true vapor pressure of 13.1 kPa (1.9 psia), and an annual average liquid concentration greater than 2 weight percent (%).

Group 2 storage vessels continue to be defined as any vessels that do not meet the Group 1 definition.

Where Refinery MACT 1 overlaps with other regulations for storage vessels (NSPS Subparts K, Ka, and Kb), after April 29, 2016:

- Group 1 tanks at an existing refinery subject to NSPS Subpart Kb and Refinery MACT 1, were only required to comply with either NSPS Subpart Kb with a few modifications listed under §63.640(n)(8) or Refinery MACT 1, per the overlap provisions in §63.640(n)(2). Refinery MACT 1 requires compliance with 40 CFR 63 Subpart WW Tanks – Control Level 2, per §63.660.
- Group 1 storage vessels that were subject to NSPS Subpart K or Ka, were only required to comply with Refinery MACT 1, per the overlap provisions.

Note under Refinery MACT 1, wastewater storage tanks at the effluent plant are not included in the definition of storage vessel - they are regulated under the wastewater regulations, which reference BWON, as noted in Table 3-8. For additional discussion, see the section under Wastewater.

Under the overlap provisions in Refinery MACT 1, Group 1 tanks that are also subject to NSPS requirements (K, Ka or Kb) are only required to meet requirements in Refinery MACT 1. Note that there are no overlap provisions specified for Group 1 Wastewater tanks.

The table below lists each tank at the refinery and identifies the basis for the applicable control requirements for each tank.

Table 3-8 Tank Applicability Matrix

AOP Tank Category	Type	Applicable Control Requirements						
		560 (SIP)	580 (SIP)	Subpart CC (MACT)	Subpart FF (BWON)	Subpart Kb (NSPS)	OAC	Phillips 66 Tank ID #
1	EFR	X	X	Group 1				6000X1, 3000X1, 1340X110, 1340X111, 1340X112, 1340X113, 1340X114, 1340X115, 1340X116, 1340X117, 800X141, 800X142, 800X143, 800X144, 800X145, 800X151, 550X101, 550X102, 550X106, 300X41, 300X42, 300X43, 300X44, 300X45
2	EFR	X	X	Group 1	X			900X1, 900X2, 900X3, 300X35, 300X46
3	EFR	X	X	Group 1			314a	100X92, 100X95
4	IFR	X	X	Group 1				400X1, 50X304, 550x100
5	IFR	X	X	Group 1	X			100X94, 100X99
6	IFR	X	X	Group 1	X		314a	300X40, 100X98
7	IFR	X	X	Group 2		X	1111	70x1 (ethanol)
8	FR or IFR	X	X	Group 2				960X1, 800X140, 800X146, 800X147, 800X148, 800X149, 800X150, 550X103, 550X104, 550X105, 300X36, 300X37, 300X38, 300X39, 100X91, 50X300, 50X301, 50X302, 50X303, 6X10, 6X11

EFR = external floating roof IFR = internal floating roof FR = floating roof
580 = NWCAA Section 580
OAC = NWCAA Order of Approval to Construct

Group 2 tanks that are subject to the control requirements under NSPS K or Ka shall comply with the provisions of NSPS K or Ka as modified under 40 CFR §63.640(n)(9). Group 2 tanks subject to NSPS K or Ka but not the associated NSPS control requirements shall comply with the Refinery MACT 1 requirements for Group 2 storage vessels.

Under the current version of NWCAA Section 580 (580.26 and 580.37), a storage tank that is subject to a federal rule (NSPS or NESHAP) is exempt from the requirements under NWCAA 580.3, 580.9, and 560. However, these exemptions are not in the current State Implementation Plan (SIP) and, therefore, are not federally enforceable. The 580 and 560 requirements in the SIP continue to apply and are listed the AOP. Because of this discrepancy, only the SIP-adopted version of NWCAA 580 citations is found in the AOP.

The applicability of these programs varies depending on tank capacity; construction, reconstruction, or modification date; vapor pressure (VP); and organic or HAP content of stored liquid. To demonstrate regulatory inapplicability for specific tanks, records demonstrating that the type of product stored and vapor pressures, periods of storage, and storage capacities of each tank should be kept.

The criteria for vessels to be subject to specific control requirements are summarized in the table below.

Table 3-9 Control Requirement Thresholds for VOL Storage Vessels

Control Requirements Thresholds	kPa	psia
NWCAA control for tanks ≥ 40,000 gallons (151 m^3)	(10.4)	1.5
NSPS K & Ka control for tanks ≥ 40,000 gal (151 m^3)	(10.4)	1.5
NSPS Kb control for tanks ≥ 151 m^3 (40,000 gal)	5.2	(0.75)
NSPS Kb control for tanks ≥ 75 m^3 (19,800 gal)	27.6	(4.0)
Refinery MACT 1 Group 1 tanks: ≥ 151 m^3 (40,000 gal)	5.2	(0.75)
Refinery MACT 1 Group 1 tanks: > 76 m^3 (20,000 gal), < 151 m^3 (40,000 gal)	13.1	(1.9)
NWCAA & NSPS MTVP of stored VOL for EFR or IFR tanks	76.6	11.1

Note: Federal regulations use IS units, whereas the NWCAA regulation uses English units. Values in parentheses are calculated.

3.2.2.2 40 CFR 63 Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery

Subpart UUU (commonly referred to as Refinery MACT 2), originally published on April 11, 2002, and amended thereafter requires controls and work practice standards for hazardous air pollutants from catalytic cracking units (FCCU), sulfur recovery units (SRU) and catalytic reformers (#3 Reformer). Subsequent amendments based on petitions for reconsideration received by EPA resulted in revisions finalized July 13, 2016, November 26, 2018, and most recently, February 4, 2020. The RTR amendments to Refinery MACT 2 resulted in the following changes:

- Removal of startup, shutdown, and malfunction exemptions
- Addition of alternate work practices and associated monitoring systems during periods of startup and shutdown for FCCUs and SRUs, and during periods of hot standby, for FCCUs

With this third renewal of the AOP, changes resulting from amendments to Refinery MACT 2 have been incorporated.

Alternate Work Practices: With removal of the provisions that allowed for excess emissions during periods of startup, shutdown or malfunctions, Phillips 66 must now meet alternate work practices standards. The following work practice standards and use of continuous parameter monitoring systems (CPMS) are required for specific units during specific operations, as noted below:

- SRU: Startup or shutdown - operate the incinerator above 1200° F and 2% O_2.
- FCCU: Startup, shutdown, or hot standby - operate at or above 1% O_2 from the regenerator.

Catalytic Cracking Units (CCUs): Refinery MACT 2 limits emissions of metal HAPs and organic HAPs from a CCU that is subject to the particulate matter and CO (surrogates for metal and organic HAP, respectively) emission limits in NSPS Subpart J by requiring compliance with the particulate matter and CO limits in NSPS Subpart J. Compliance is demonstrated by meeting emission limitations, operating limitations using continuous parameter monitoring systems (CPMS), and preparation of unit-specific operation, maintenance, and monitoring plans (OMMP) for particulate matter and CO.

Particulate emissions from the refinery's FCCU are controlled using a wet scrubber. Phillips 66 follows an alternate monitoring plan (AMP) approved by EPA, renewed April 7, 2019 (Attachment A). This AMP was required to be renewed following the RTR initiative when the visible emission operating limit was restricted to 20% opacity. This AMP is used in lieu of installation and operation of a continuous opacity monitoring system (COMS).

Catalytic Reforming Units (CRUs): Refinery MACT 2 limits emission of organic HAP for each applicable process vent on a new or existing CRU during catalyst depressuring and purging operations and inorganic HAP during coke burn-off and catalyst rejuvenation.

Organic HAP emissions are limited by venting emissions during catalyst depressurizing and purging operations to a flare meeting the requirements of §63.670. Compliance is demonstrated by limiting visible emissions from the flare, ensuring the flare pilot light is present at all times, and the flare is operating at all times emissions are vented to it; determining flare exit velocity and net heating value for the gas being combusted and conducting visible emission observations; and installing and operating a flare monitoring system that meets the requirements of §63.670 and §63.671.

Inorganic HAP emissions from the #3 Reformer during coke burn-off and catalyst rejuvenation are limited by reducing the uncontrolled emissions of HCl to a concentration of no more than 10 ppmv (dry basis), corrected to 3% oxygen. Compliance is demonstrated by measuring average HCl emission during a performance test; determining an operating limit for HCl concentration using data recorded from CPMS and performance testing; and meeting the daily average HCl concentration in the catalyst regenerator exhaust gas established during the performance test.

Sulfur Recovery Units (SRUs): Refinery MACT 2 limits emissions of HAP for each new or existing Claus SRU with a design capacity greater than 20 long tons per day that is subject to the SO_2 limit in NSPS Subpart J by requiring compliance with the SO_2 limit in NSPS Subpart J or NSPS Subpart Ja. Compliance is demonstrated by meeting emission limitations, installing and operating CPMS to meet operating limitations, and preparation of unit specific OMMP based on SO_2 emissions.

Operation, Maintenance and Monitoring Plans (OMMP): The refinery was required to provide updates to the operation, maintenance, and monitoring plans (OMMP) for HAP emissions from the FCCU regenerator and SRUs during startup and shutdown to reflect changes following the RTR initiative. The OMMP revisions addressed operation of continuous parameter monitoring systems (CPMS) during startup and shutdown. The current plan was updated in August 2017.

Equipment that Refinery MACT 2 does not apply to:

- Thermal catalytic cracking units,
- SRUs that do not recover elemental sulfur or where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur (e.g., the LO-CAT II process),
- A redundant SRU not located at a petroleum refinery and used only for emergency or maintenance backup,

- Equipment associated with bypass lines such as new low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons, and
- Gaseous streams routed to a fuel gas system, provided that the flare receiving the gas from the fuel gas system is subject to §63.670.

Alternative Monitoring Plans: Phillips 66 has requested alternative monitoring plans (AMP) (Attachment A) from EPA for the following equipment/systems subject to NESHAP monitoring requirements:

FCCU WGS:

- Monitoring in lieu of COMs – NSPS Subparts A and J; NESHAP Subparts A and UUU: The FCCU is equipped with a wet gas scrubber. The high moisture content in the WGS flue gas prevents the use of a continuous opacity monitoring system, so the refinery requested to monitor liquid-to-gas ratio, calculated as a function of the discharge pressure of the slurry pump, established through annual performance testing, and installation of an alarm to warn refinery personnel when the liquid-to-gas ratio falls below the minimum set point, in lieu of installing and operating a continuous opacity monitoring system (COMS). EPA approved the AMP March 31, 2006, with excess opacity emissions for both 40 CFR 60 Subpart J and 40 CFR 63 Subpart UUU. The AMP was renewed by the EPA on April 17, 2019.
- Monitoring in lieu of COMs – NSPS Subparts A and J: Requires installation, operating, calibration and maintenance of a total reduced sulfur CEMS according to PS 5 in Appendix B and subject to applicable quality assurance procedures in Appendix F. In September 2002, Phillips 66 applied for an AMP to monitor fuels loaded at the truck rack meet specific sulfur product specifications. Phillips 66 received approval of the AMP from the EPA on April 9, 2003.
- Monitoring in lieu of COMs – NSPS Subparts A and Ja: Requires installation, operating, calibration and maintenance of a total reduced sulfur CEMS according to PS 5 in Appendix B and subject to applicable quality assurance procedures in Appendix F. The SRUs could send pure H_2S to the flare during upset conditions, requiring daily calibration checks with a high concentration of sulfur span gas which would be a safety hazard for operators. In May 2016, Phillips applied for an alternative monitoring plan requesting to use low span H_2S gas and showing a correlation between SO_2 as an analyte. The AMP was approved on April 17, 2019.

3.2.2.3 <u>40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</u>

40 CFR 63 Subpart ZZZZ was promulgated on June 15, 2004, applying NESHAP standards to stationary reciprocating internal combustion engines (RICE) with a size rating of greater than 500 brake horsepower. The rule was amended on January 18, 2008, subjecting RICE with a size rating of equal to or less than 500 brake horsepower to the rule then amended again in 2013 and 2020.

The following engines located at Phillips 66 are subject to Subpart ZZZZ. All are diesel-fired, compression ignition (CI) engines in dedicated emergency service. There are no stationary, spark ignition engines at the refinery subject to the rule.

Table 3-10 Engines Subject to 40 CFR 63 Subpart ZZZZ, PPPPP, and/or 40 CFR Subpart IIII

Emission Unit	Construction / Modification	Notes
Spark Ignition Octane Test Engines (subject to 40 CFR 63 Subpart PPPPP with no requirements)		
Waukesha Model MON (949817)	1954	Inside lab, octane test engine
Waukesha Model Swing (354050)	1980	Inside lab, octane test engine
Waukesha Model RON (R-F5039)	1981	Inside lab, octane test engine
Emergency, Compression Ignition Engines ≤ 500 hp (subject to 40 CFR 63 Subpart ZZZZ "existing")		
Detroit Model 62402RA (26-GV-4)	1953	Beach area, 264 hp, firewater pump
Detroit Model 62402RA (26-GV-5)	1953	Beach area, 264 hp, firewater pump
Detroit Model 62402RA (26-GV-6)	1953	Beach area, 264 hp, firewater pump
Kohler Model 20R0274 (22-GEN-0164)	1986	Boiler area, 61 hp, emergency generator
Deutz BF6L914C (26G-0105A)	2007	Wastewater Treatment Plant, 174 hp, emergency generator
Deutz BF6L914C (26G-0105B)	2007	Wastewater Treatment Plant, 174 hp, emergency generator
Emergency, Compression Ignition Engines ≤ 500 hp (subject to 40 CFR 60 Subpart IIII & 40 CFR 63 Subpart ZZZZ "new")		
Cummins Model QSB5-63 NR3 (10G-100)	2009	Foam Building, 132 hp, emergency generator
Kubota Model C2203-EBG (24-GEN-0101)	2008	TEL area, 33 hp, emergency generator
Caterpillar Model C9 (29-GEN-01)	2007	ROC area, 398 hp, emergency generator
John Deere Model 4045TF150 (21GEN-201)	2012	Reformer, 115 hp, emergency generator
Generac 17922860200 (90GEN-0001)	2014	Radio Building, 85 hp, emergency generator
Emergency, Compression Ignition Engines > 500 hp (subject to 40 CFR 63 Subpart ZZZZ "existing" with no requirements)		
Caterpillar Model 3456 (24GEN-0103)	11/13/2002	Alky Unit, 800 hp, emergency generator
Cummins Model K11A19G2 (12-GCP-2701)	1991	Wastewater treatment plant, 750 hp, emergency generator
Cummins Model VT-1710-F (29GV-09)	1953	Cooling tower area, 685 hp, firewater pump
Emergency, Compression Ignition Engine > 500 hp (subject to 40 CFR 63 Subpart ZZZZ "new" with no requirements)		
Caterpillar Model 3412 (26G-103)	12/29/2004	Boiler area, 739 hp, firewater pump
Emergency, Compression Ignition Engine > 500 hp (subject to 40 CFR 60 Subpart IIII & 40 CFR 63 Subpart ZZZZ "new")		
Caterpillar C18 (26G-0106A)	2008	Wastewater treatment plant, 700 hp, emergency generator
Caterpillar C18 (26G-0106B)	2008	Wastewater treatment plant, 700 hp, emergency generator

None of the emergency generator engines at Phillips 66 are contractually obligated to be available for more than 15 hours per calendar year for emergency demand response as specified in §63.6640(f)(2)(ii), for assisting in voltage/frequency deviations as specified in §63.6640(f)(2)(iii), or for non-emergency situations to supply power as part of a financial arrangement with another entity as specified in §63.6640(f)(4)(ii).

To remain in the emergency use category under Subpart ZZZZ, §63.6640(f)(2) limits the number of hours per calendar year in non-emergency service to 100 hours if it is used for recommended maintenance checks and readiness testing. There is no limit to the number of hours an engine can run while in emergency service.

There are four engine categories based on their age and size that determine compliance obligations for emergency IC engines under Subpart ZZZZ.

1. Existing engines ≤ 500 HP constructed before June 12, 2006.

   §63.6590(a)(1) states:

   (i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

   The four engines at the refinery under this category are listed in Section 5 of the AOP along with requirements of Subpart ZZZZ. The requirements include replacing the engine lube oil and intake air filter on a periodic basis to ensure the engines are kept in good operating condition.

2. New engines ≤ 500 HP constructed on or after June 12, 2006.

   §63.6590 states:

   (c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

   (6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

   All these CI engines at the refinery are subject to NSPS 40 CFR 60 Subpart IIII. Because 40 CFR 63 Subpart ZZZZ relies on the provisions of Subpart IIII for compliance, the NSPS requirements are included in the AOP for these engines.

3. Existing engines > 500 HP constructed before December 19, 2002.

   §63.6590(b) states:

   (b) Stationary RICE subject to limited requirements.

   (3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

   (iii) Existing 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).

   All these CI engines at the refinery meet the (iii) criteria and have no requirements under Subpart ZZZZ. These engines are not listed in Section 5 of the AOP.

4. New engines > 500 HP constructed on or after December 19, 2002.

§63.6590(b) states:

(b) Stationary RICE subject to limited requirements.

(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).

(i) 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).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

The refinery has one IC engine in this category that requires only initial notification under Subpart ZZZZ. The initial notification for the Caterpillar Model 3412 generator engine was received by the agency on January 14, 2005, stating that the engine was installed on December 29, 2004. This one-time only requirement has been completed and there are no ongoing requirements under Subpart ZZZZ. This engine is not listed in Section 5 of the AOP.

3.2.2.4 40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63 Subpart DDDDD applies to industrial, commercial, or institutional boilers and process heaters that are located at a major source of hazardous air pollutants (HAPs), commonly referred to as the Major Source Boiler MACT (Boiler MACT). Boiler MACT was revised November 20, 2015; however, the revisions do not affect the requirements that apply at Phillips 66. On May 23, 2013, the NWCAA received initial notification from the refinery listing their existing process heaters and boilers subject to Subpart DDDDD. They are considered "existing" units because they were constructed prior to the June 4, 2010, applicability date for "new" units under the rule.

On October 23, 2015, the NWCAA issued OAC 1223 approving the Tier III Hydrotreater Unit. The Tier III Hydrotreater includes a new Tier III Hydrotreater Charge Heater. Because this process heater was constructed after the June 4, 2010, applicability date, it is considered a "new" heater under Subpart DDDDD.

All the process heaters and boilers at the refinery subject to Subpart DDDDD are fired exclusively on natural gas and/or refinery fuel gas and fall under the "units designed to burn gas 1 fuels" subcategory. Subpart DDDDD does not require any pollutant-specific emission limits for process heaters and boilers designed to burn gas 1 fuels. Instead, it requires work-practice standards involving an initial energy assessment for existing units and periodic tune-ups for both new and existing units.

The subject heaters and boilers at the refinery are designed to burn gas 1 fuels. Per the February 7, 2019 letter from Erin Strang, Phillips 66, to Dan Mahar, NWCAA – all boilers/heaters subject to DDDDD are on an annual tune-up frequency. There are no differences between the tune-up requirements for new versus existing heaters or boilers. The MACT requirement for subject heater and boilers was moved to Section 6, as it applies to all process heaters and boilers at the refinery.

In addition, the existing heaters and boilers are required to undergo an initial energy assessment, whereas new heaters and boilers do not have this initial requirement. On

March 24, 2016, the NWCAA received a notice of compliance status report from Phillips 66 stating that the initial energy assessments that were required by January 31, 2016, had been completed for all existing heaters and boilers at Phillips 66. Because the one-time only energy assessments were completed, they are not listed in the AOP.

The CO Boiler at the FCCU qualifies as a boiler under Subpart DDDDD, however, it is also subject to 40 CFR 63 Subpart UUU and therefore not subject to Subpart DDDDD pursuant to the overlap provision in 40 CFR §63.7491(h). The FCCU also includes a Combustion Air Heater that directly fires into the fluid catalytic cracker prior to the regeneration section. In general, this Combustion Air Heater is not used except during startups and in some cases during troubleshooting. The FCCU Combustion Air Heater is not considered a process heater under Subpart DDDDD because it is direct fired, whereas the rule defines process heaters as those that are not direct fired. In 2016, Boiler MACT reports submitted by the refinery included the FCCU Combustion Air Heater inferring that it is subject to Subpart DDDDD. However, the FCCU Combustion Air Heater is not subject to Subpart DDDDD and the AOP has been written accordingly.

Table 3-11 lists the process heaters and boilers that are subject to Boiler MACT located at the Phillips 66 Ferndale Refinery.

Table 3-11 Boilers and Process Heaters Subject to Subpart DDDDD

Process Unit	Process Heaters	Refinery ID #	New or Existing
Crude	Crude Heater	1F-1	Existing
Crude	Supplemental Crude Heater	1F-1A	Existing
FCC	Vacuum Flasher Heater	4F-2	Existing
Alky	Alkylation Depropanizer Reboiler	17F-1	Existing
Reformer	#3 Reformer Heaters	18-F21, F22, F23 & F24	Existing
Reformer	#3 Reformer Pretreater Heater	18F-1	Existing
Reformer	#3 Reformer Regenerator Heater	18F-26	Existing
DHT	Diesel Hydrotreater Heater	33F-1	Existing
CGD/S-Zorb	Cat Gas Desulfurizer Feed Heater (S-Zorb Heater)	38F-101	Existing
Tier III Hydrotreater	Tier III Hydrotreater Charge Heater	41F-1	New
Utilities	#1 Boiler	22F-1C	Existing
Utilities	#2 Boiler	22F-1A	Existing
Utilities	#3 Boiler	22F-1B	Existing
Utilities	#4 Boiler	22F-1E	Existing

3.2.2.5 40 CFR Part 63 Subpart PPPPP – National Emission Standards for Hazardous Air Pollutants for Engine Test Cells/Stands

40 CFR 63 Subpart PPPPP applies to the emissions of hazardous air pollutants (HAPs) at engine test cells/stands located at major sources of HAP emissions. The refinery maintains three octane test engines in the lab for fuel testing, which qualify as engine test cells. All three octane test engines were installed prior to May 14, 2002, and are considered existing engine test cells/stands under the rule. Pursuant to 40 CFR §63.9290(b), existing engine test cells/stands are subject to the rule but do not have to meet any of the requirements of Subpart PPPPP and 40 CFR 63 Subpart A.

The three octane test engines listed below are also listed in Section 1 of the air operating permit. However, they are not in Section 5 of the AOP because there are no specific requirements under Subpart PPPPP for these engines.

- Waukesha Model MON (949817), manufactured in 1954
- Waukesha Model Swing (354050), manufactured in 1980
- Waukesha Model RON (R-F5039), manufactured in 1981

3.3 Prevention of Significant Deterioration

The Prevention of Significant Deterioration (PSD) program is a federal new source review program that applies to construction of major new sources and major modifications that occur in areas that are in attainment with the National Ambient Air Quality Standards (NAAQS). The PSD program stems from 40 CFR parts 50, 51, and 52. The PSD permitting process ensures that air quality is maintained in attainment areas. Effective April 30, 2021, the area directly north of the refinery is not in attainment (referred to as nonattainment) for the 2010 Sulfur Dioxide standard. This designation will not affect permitting at the refinery. The PSD permit establishes best available control technology (BACT) for the new and modified emission units. The EPA has partially delegated the PSD rules to the Washington State Department of Ecology (WDOE) which writes PSD permits covering emissions of criteria pollutants for which a facility or a project is major.

The Phillips 66 refinery has received two PSD permits. As described below in Section 4 of the Statement of Basis, the WDOE issued PSD permit #PSD-00-02 on April 4, 2001, for the Upgrade/Clean Fuels project associated with a large-scale upgrade of the refinery and installation of equipment needed to make low sulfur gasoline. As of the date of this permit issuance, PSD-00-02 has been amended eight times. The Upgrade/Clean Fuels project triggered PSD for nitrogen oxides, carbon monoxide, and particulate matter 10 microns in diameter or less (PM_{10}). Other pollutants are addressed in NWCAA OAC 733 and its subsequent revisions.

The second permit issued by the WDOE to the Phillips 66 refinery is PSD-05-01 issued November 14, 2005, for the Crude/Fluidized Catalytic Cracking/Sulfur Recovery Unit project. The project was designed to increase feed rates at the Crude Unit and at the FCCU, increase the primary amine system capacity to remove more sulfur from fuel gas, and add a second sulfur recovery unit (SRU #2) to provide backup capacity and additional sulfur removal capacity. The project triggered PSD review for nitrogen oxides, carbon monoxide, total particulate matter, PM_{10}, and VOCs.

3.4 Consent Decree

On December 5, 2005, a complaint, and a Consent Decree (CD) were filed by the United States Justice Department, on the behalf of the Environmental Protection Agency and five co-plaintiffs, including the Northwest Clean Air Agency, against Phillips 66 (ConocoPhillips at that time). The United States alleged that the company violated statutory and regulatory provisions at twelve refineries in the United States, including Phillips 66.

ConocoPhillips denied that it had violated the statutory, regulatory, and SIP provisions and the state and/or local rules and regulations incorporating and implementing federal requirements and maintained that it had been and remains in compliance with all applicable statutes, regulations and permits and was not liable for civil penalties and injunctive relief.

The process culminated in a settlement where ConocoPhillips agreed to take numerous actions to reduce air pollutants at Phillips 66. Many of these obligations have been converted into federally enforceable requirements that are written into NWCAA regulatory orders, NWCAA OACs and WDOE PSD permits to provide permanence and these requirements are included in the AOP. Other requirements in the CD are considered an enhancement of existing requirements and will terminate with the CD. These requirements are not Title V applicable requirements and have not been included in the AOP.

On April 29, 2019, the NWCAA completed a review of the obligations necessary to terminate the CD, including language in the CD, conditions in construction permits that incorporate CD requirements, and a review of the Federal Refinery semiannual CD progress report covering the second half of 2018. All one-time requirements have been completed and all CD-based emission limits have been incorporated into either OAC or PSD permits making the limits enforceable after CD termination.

On October 31, 2019, Phillips 66 petitioned the court to terminate the CD and this process is ongoing as of issuance of this renewal permit. Since the process is still ongoing, requirements of the CD remain in the AOP.

3.5 Compliance Assurance Monitoring (CAM)

The 40 CFR Part 64 CAM rule requires owners and operators to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether their facilities meet established emission standards. If owners and operators of these facilities find that their control equipment is not working properly, the CAM rule requires them to take action to correct any malfunctions and to report such instances to the appropriate enforcement agency (i.e., State, and local environmental agencies). If there are relatively frequent excursions of the monitoring parameters, the rule requires that the facility implement a quality improvement program (QIP) to reduce excursions. Additionally, the CAM rule provides enforcement tools that help agencies address appropriate monitoring of pollution control systems.

The CAM rule applies to each Pollutant Specific Emissions Unit (PSEU) when it is located at major source required to obtain an air operating permit. Each PSEU must meet all the following criteria:

- be subject to an emission limitation or standard,
- use a control device to achieve compliance,
- have an uncontrolled potential to emit equal to or greater than the major source threshold, e. g., 100 tons PM_{10}, NO_X, SO_2.

The term PSEU means an emissions unit considered separately with respect to each regulated air pollutant. Also, the term “control device” means equipment, other than inherent process equipment, that is used to destroy or remove air pollutants prior to discharge to the atmosphere. Low NO_X burners are considered inherent process equipment because they cannot be activity adjusted during use; whereas flue gas recirculation is considered an active control system that can be used or bypassed during operation. The term “control device” does not include passive methods such as lids or seals, or inherent process equipment provided for safety or material recovery.

If the PSEU has a controlled potential to emit equal to or greater than the major source threshold, it is considered a “large PSEU” and monitoring parameters must be recorded at least once every 15 minutes. If the controlled potential to emit is less than the major source threshold, the PSEU is considered an “other PSEU” and monitoring parameters must be recorded at least once per day.

The following emission limitations or standards are exempted from the CAM rule:

- post 11/15/90 NSPS or NESHAP standards, since those standards have been and will be designed with monitoring that provides a reasonable assurance of compliance,
- stratospheric ozone protection requirements under Title VI of the act,
- acid rain program requirements,
- emission limitations or standards or other requirements that apply solely under an approved emissions trading program,
- emissions cap that meets requirements of 70.4(b)(12) or 71.6(a)(13),
- emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 40 CFR 64.1,
- certain municipally owned utility units, as defined in 40 CFR 72.2.

The emission unit is not exempted from the CAM rule if nonexempt emission limitations or standards (e. g., a state rule or older NSPS emission limits) apply to the emissions unit.

The CAM rule (40 CFR 64) requires permits to specify, at minimum:

- The approved monitoring approach, including the indicators (or the means to measure the indicators) to be monitored, and performance requirements established to satisfy 40 CFR 64.3 (b) or (d), as applicable,
- The means by which the owner or operator will define exceedances or excursions,
- The duty to conduct monitoring,
- If appropriate, minimum data availability and averaging period requirements; and
- milestones for testing, installation, or final verification.

The following PSEU are subject to CAM at the Phillips 66 Ferndale Refinery.

Table 3-12 Emission Units and Pollutants Subject to CAM

Pollutant-Specific Emission Unit	Description	Control Device	Pollutant
FCCU/CO Boiler	FCCU Regenerator/Combustion Air Heater/CO Boiler	Flue Gas Scrubber (FGS)	PM_{10}
Gases exiting the FGS are saturated with water vapor making continuous direct measurement of particulate matter difficult and unreliable. The CAM plan serves as an alternative that continuously measures operating parameters of the FGS affecting scrubber efficiency. These parameters are correlated with data taken during periodic PM/PM_{10} source tests. The CAM plan, also referred to as the alternative monitoring plan (AMP), continuously monitors the liquid-to-flue gas ratio of the FGS and the weight percent of solids in the scrubber liquid to ensure the FGS is operating properly to control emissions. The CAM Plan was incorporated into OAC 733e to memorialize the EPA approved AMP as a Consent Decree obligation. A copy of the AMP is included in Attachment A. The FCCU/COB FGS stack has a controlled PTE < 100 tpy and is considered an "other PSEU" requiring that monitoring parameters be recorded no less than daily under the CAM rule. However, the CAM plan as incorporated into OAC 733e requires hourly parameter monitoring.			
Pollutant-Specific Emission Unit	Description	Control Device	Pollutant
Truck Loading Rack	Gasoline/Diesel Truck Load Rack	Thermal Oxidizer	VOC
For CAM, the temperature in the thermal oxidizer is monitored continuously during loading to ensure that a minimum temperature of 450°F is maintained. The Truck Loading Rack thermal oxidizer stack has a controlled PTE < 100 tpy and is considered an "other PSEU" requiring that monitoring parameters be recorded no less than daily under the CAM rule. However, the CAM plan, as incorporated into the AOP, requires continuous monitoring of the thermal oxidizer temperature to determine complinace.			

The following emission units are not subject to CAM.

Table 3-13 Emission Units and Pollutants not subject to CAM

PSEU Designation	Unit Description	Pollutant & Reasons for Non-Applicability*
Crude Distillation Process Area	• 1F-1A Crude Heater • 1F-1 Crude Heater	PM - The combustion units have grain loading standards for PM; however, CAM does not apply because they do not have active control devices. SO_2 – Unit equipped with CEM
	• HDF Stripper Offgas Process Vent	post – 11/15/90 regulatory standard
Catalytic Cracking Process Area	• FCCU Regenerator/Combustion Air Heater/CO Boiler	Metal HAP – Post 11/15/90 regulatory standard NO_X – Unit equipped with CEM CO – Unit equipped with CEM SO_2 – Unit equipped with CEM PM - The combustion unit has grain loading standards for PM; however, CAM does not apply because it does not have an active control device.
	• 4F-2 Vacuum Flasher Heater	SO_2 – No control device NOx – CEM PM - The combustion unit has grain loading standards for PM; however, CAM does not apply because it does not have an active control device.
	• Process Vent 25FV-007	post – 11/15/90 regulatory standard
Alkylation Process Area	• Process Vent 17HC-1717	post – 11/15/90 regulatory standard
	• 17F-1 Alky Depropanizer Reboiler Heater • 38F-101 Cat Gas Desulfurizer Feed Heater (S-Zorb Heater)	PM - The combustion unit has grain loading standards for PM; however, CAM does not apply because it does not have an active control device.
Tier III Hydrotreater Process Area	• Tier III Hydrotreater Charge Heater	PM - The combustion unit has grain loading standards for PM; however, CAM does not apply because it does not have an active control device.

PSEU Designation	Unit Description	Pollutant & Reasons for Non-Applicability*
Reformer/Diesel Hydrotreater Process Area	• 18F-1 #3 Reformer Pretreater Heater • 18F-26 #3 Reformer Catalyst Regeneration Heater • 33-F-1 Diesel Hydrotreater (DHT) Heater • 18F-21, -22 #3 Reformer Heater, Passes 1 and 2 • 18F-23, -24 #3 Reformer Heater, Passes 3 and 4	PM - The combustion units have grain loading standards for PM; however, CAM does not apply because they do not have active control devices.
	• Miscellaneous Process Vents	post – 11/15/90 regulatory standard
	• #3 Reformer Regeneration Vents	post – 11/15/90 regulatory standard
Sulfur Plant/Treaters Process Area	• Sulfur Recovery Unit #1	SO_2 – Unit equipped with CEM NOx - no control device CO – no control device
	• Sulfur Recovery Unit #2	SO_2 – Unit equipped with CEM NOx - no control device CO – no control device HAP – post-11/15/90 regulatory standard
Utilities Process Area	• 22F-1C #1 Boiler with Flue Gas Recirculation	NOx – Unit equipped with CEM PM - The combustion unit has grain loading standards for PM; however, CAM does not apply because it does not have an active control device.
	• 22F-1A #2 Boiler • 22F-1B #3 Boiler • 22F-1E #4 Boiler • Cooling Tower #1 • Cooling Tower #2	PM - The combustion units have grain loading standards for PM; however, CAM does not apply because they do not have active control devices.

PSEU Designation	Unit Description	Pollutant & Reasons for Non-Applicability*
Wastewater Treatment Plant	• 12S-204 Induced Air Flotation Unit (IAF) • 12S-2 API Separator • Individual Drain Systems • Closed vent systems and control devices • Vacuum trucks	These units are subject to MACT Subpart CC and NESHAP Subpart FF. Subpart CC, finalized in 1995 and amended in 2009 and 2010, references Subpart FF for wastewater requirements including monitoring. Since the Subpart FF reference and wastewater monitoring requirements were not amended in the initial Subpart CC promulgation or the 2009/1010 amendments, the facility is exempt from CAM due to a post-11/15/90 regulatory standard. Individual drain systems subject to only NSPS QQQ are minimal at the facility and presumed to have exempt amounts of pre-control emissions.
Storage and Handling	• Tank Farm • Butane/Pentane Spheres	These units do not have active control devices. They only use passive controls, which are CAM exempt.
Flares	• Flare Gas Recovery • Elevated Flare (13V-11)	These units do not have control devices.
Fuel Gas S_2 Content	• Fuel Gas Combustion in various units	H2S – amine treatment system. Otherwise exempt – equipped with continuous compliance determination method of CEM
** Note that numerous units are also monitored by CEMs. See Table 3-14 for a list of CEMs.*		

3.6 Risk Management Plan

The goal of 40 CFR Part 68 and the risk management program is to prevent accidental releases of substances that can cause serious harm to the public and the environment from short-term exposures and to mitigate the severity of releases that do occur. If a facility contains the hazardous or flammable substances listed in 40 CFR §68.130 in an amount above the "threshold quantity" specified for that substance, the facility operator is required to develop and implement a risk management program.

Phillips 66 maintains several substances in quantities greater than the listed thresholds. As such, Phillips 66 submits RMPs to the EPA as appropriate. This regulation is implemented in its entirety by the EPA. The refinery certifies ongoing compliance with all applicable requirements of 40 CFR 68 in the annual compliance certification.

3.7 Washington Administrative Code

The Washington Administrative Code (WAC) pertaining to air pollution programs are included in the AOP.

Section 2 of the AOP contains various portions of the WAC that are considered standard terms and conditions. These include WAC 173-460 requiring review of toxic air pollutant impacts during NSR permitting, WAC 173-401 establishing basic requirement of the air operating permit program, and WAC 173-441 and 173-442 regulating and reporting of greenhouse gas emissions.

Section 4 of the AOP contains generally applicable requirements of the WAC, such as limits on visible emissions, particulate matter, and sulfur dioxide from all stacks.

Section 5 of the AOP contains specifically applicable requirements from the WAC for petroleum refineries including particulate and opacity limits for catalytic cracking units (WAC 173-400-070) and VOC limits and work practice standards for gasoline loading terminals (WAC 173-491).

The AOP does not include Chapter 173-485 WAC – Petroleum Refinery Greenhouse Gas Emission Requirements. This is because Phillips 66 chose to comply with the one-time only requirement to meet an energy intensity index (EII) that is within the 50% quartile or better for similar sized refineries using national 2006 EII data for comparison. This one-time only requirement was met on September 26, 2014, when the NWCAA received the refinery's initial and final GHG annual report required under WAC 173-485-090. This report demonstrated that the calendar year 2013 greenhouse gas emissions were 769,015 tons and that at this rate the refinery was within the 50% or better EII quartile of similar refineries in the United States. In accordance with WAC 173-485-050 and 173-485-090(1), Phillips 66 has no further reporting or compliance obligations under Chapter 173-485 WAC, and it is therefore not listed in the AOP.

3.8 Northwest Clean Air Agency Regulation

The NWCAA Regulation contains requirements that are generally applicable to a wide group of air pollution sources. These generally applicable requirements are found in Section 4 of the AOP. These include requirements such as the 1,000 ppm sulfur dioxide limit for combustion sources in NWCAA Section 462 and the 20% opacity limit for stacks found in NWCAA Section 451.

The NWCAA regulation also contains numerous emission unit specific requirements. These are found in Section 5 of the AOP. As an example, NWCAA Section 580 applies to petroleum refineries and has specific requirements for storage vessels, equipment component leaks, process unit turnarounds, vacuum systems, and gasoline truck loading racks.

The NWCAA new source review regulations reflect state and federal NSR regulations. The federal system to implement the Clean Air Act (programs related to the NAAQS) may be administered by the federal government or may be delegated (in part) to states, such as Washington, that seek regulation through State Implementation Plans (SIPs). Certain state and local regulations are part of the Washington State Implementation Plan and are therefore enforceable by both the EPA and the NWCAA.

These SIP approved rules are in the operating permit. There is often a lag between the current state/local regulation and the version of that state/local regulation approved in the SIP. In this case the AOP will list the current, non-SIP approved regulation identified as "state only" and the SIP-approved, federally enforceable version of the regulation in the air operating permit.

The NWCAA can enforce, but not issue PSD permits. The NWCAA has authority to enforce local, state, and most federal regulations and to fully enforce the air operating permit.

3.9 Refinery Gas Systems

Waste gases produced during refinery processing are delivered via fuel gas systems for combustion in heaters and boilers throughout the refinery. If the refinery is short on refinery generated fuel gas, the fuel gas system is supplemented with purchased natural gas.

Refinery fuel gas contains sulfur, primarily in the form of hydrogen sulfide (H_2S), which is converted to sulfur dioxide (SO_2) when combusted. New and modified combustion units have restrictions on the concentration of H_2S in the fuel gas through BACT limits contained in OACs or from federal NSPS regulations.

There are three sources of refinery fuel gas systems at Phillips 66: the main refinery fuel gas system, the reformer fuel gas system and the FCCU absorber offgas (overhead gas). The main refinery fuel gas system is comprised of light gases generated at a wide variety of process units within the refinery. This fuel gas is combusted in heaters and boilers throughout the refinery that do not have a separate supply of fuel gas. In general, the main refinery fuel gas system cannot supply all the fuel needed to the heaters and boilers that it supports, and the main refinery fuel gas system is supplemented with purchased natural gas and excess gas from the reformer fuel gas and FCCU absorber offgas systems.

The main refinery fuel gas system is limited to 162 ppm H_2S, 3-hour average through NSPS and OAC requirements. The new Tier III Hydrotreater Charge Heater will combust main refinery fuel gas and will also be limited to 50 ppm H_2S, 24-hour average as required as BACT under OAC 1223.

The reformer fuel gas system is supplied by gas generated at the #3 Reformer and supplies fuel gas to the heaters in the #3 Reformer Unit and DHT Unit. Depending on operating conditions, there may be an excess amount of fuel gas generated at the #3 Reformer with the excess used to supplement the main refinery fuel gas system. There may also be times when the heaters at the #3 Reformer and DHT Units use more fuel gas than is generated at the #3 Reformer. In this case the reformer fuel gas system is supplemented with gas from the main refinery fuel gas system. The reformer fuel gas is limited to 162 ppm H_2S, 3-hour average through NSPS and OAC requirements. The H_2S concentration of the fuel gas is also limited to 50 ppm, 24-hour average under BACT conditions established under OAC 733f and OAC 780b for gas combusted in the DHT Heater.

The third fuel gas system in the refinery is the FCCU absorber offgas (overhead gas). This gas is generated at the FCCU and combusted in the CO Boiler for supplemental firing of that boiler. The CO Boiler can also combust gas from the main refinery fuel gas system for additional supplemental firing. The FCCU absorber offgas is limited to 162 ppm H_2S, 3-hour average under NSPS when combusted in the CO Boiler.

The #4 Boiler and S-Zorb Heater are approved to combust refinery fuel gas, however, often combust only natural gas. During periods when only natural gas is combusted in a heater or boiler, the H_2S limit does not apply.

All three fuel gas systems at the refinery (main, reformer and FCCU absorber) are scrubbed with amine to reduce the H_2S content of the gas prior to combustion to below applicable H_2S limits. In addition, the H_2S concentration in each fuel gas is continuously monitored to ensure compliance in accordance with the monitoring provisions of NSPS Subpart J or Ja. These NSPS regulations state the standard in mg/liter instead of concentration. However, the AOP states the limits in terms of ppm concentration because ppm is the measured parameter from the continuous H_2S monitors.

The conversion from the NSPS H_2S limit of 230 mg/dscm to the AOP stated value of 162 ppm is done using standard conditions of 20°C and 760 mm Hg as follows.

Equation 3-1

$$\frac{230\ mg\ H2S}{dscm\ air} \times \frac{1\ g\ H2S}{1{,}000\ mg\ H2S} \times \frac{1\ mol\ H2S}{34.082\ g\ H2S} \times \frac{24.056\ L\ H2S}{mol\ H2S\ (ideal\ gas\ law)} \times \frac{1\ dscm\ H2S}{1{,}000\ L\ H2S} = \frac{162\ dscm\ H2S}{1{,}000{,}000\ dscm\ air}$$
$$= 162\ ppmdv\ H2S\ in\ air$$

In addition to H_2S limits in refinery fuel gas, process heaters and boilers at the refinery are subject to a SO_2 limit of 1000 ppm, 1-hour average in the exhaust stack per WAC 173-400-040 and NWCAA Section 462. In general, H_2S represents most sulfur species in the refinery fuel gas and knowledge of the H_2S concentration in the fuel gas provides a good approximation of stack SO_2 values. To ensure compliance with the 1000 ppm standard, the refinery conducts periodic sampling of the fuel gas to identify all sulfur species, continuously monitors the gas specific gravity of the fuel gas and continuously monitors the total reduced sulfur (TRS) in the flare header. When the refinery fuel gas includes hydrogen, the carbon to hydrogen ratio must be accounted for in calculating SO_2 emissions. The specific gravity of the fuel gas helps to determine the carbon to hydrogen ratio when making this calculation.

3.10 Continuous Emission Monitoring Systems (CEMS)

Continuous emission monitoring systems (CEMS) are in place throughout the refinery to monitor compliance with air pollution limits and standards. CEMS are installed and operated in accordance with applicable federal requirements of 40 CFR 60 Appendices B and F, and NWCAA Regulation Section 367 and Appendix A - Ambient Monitoring, Emission Testing, and Continuous Emission and Opacity Monitoring. CEMS are quality assurance tested as required under 40 CFR 60 Appendix F and NWCAA 367 and Appendix A. This includes conducting quarterly cylinder gas audits (CGA) and annual relative accuracy test audits (RATA). The duration and nature of CEM downtimes is reported to the NWCAA in monthly reports. The monthly reports also include CGA and RATA results. Under NWCAA Regulation Section 340 measured emission exceedances are reported to the NWCAA when discovered and explained in more detailed in the Part II excess reports. When a CEMS is sampling from a stack, the oxygen concentration is measured so that the pollutant concentration can be corrected to the appropriate percent oxygen value stated in the limit or standard.

Table 3-14 CEMS at Phillips 66

Process Unit	CEMS Location	Compounds Monitored	Requirement
FCCU	WGS inlet and outlet	SO_2	OAC 733f, NSPS J
FCCU	WGS outlet	NO_X	PSD-00-02
FCCU	CO Boiler stack	CO	PSD-00-02, CO-13, NSPS J
FCCU	Catalyst Regenerator Vent	CO	NESHAP UUU
Refinery Fuel Gas	Fuel gas drum	H_2S	OAC 733f, NSPS J
Vac Tower	Vac Tower Stack	NO_X	OAC 733f, NSPS J
S-Zorb	S-Zorb fuel gas drum	Fuel gas H_2S	OAC 733f
Tier III/LSR	Tier III/LSR fuel gas drum	Fuel gas H_2S	OAC 1223, NSPS Ja
#3 Reformer	#3 Reformer fuel gas drum	Fuel gas H_2S	OAC 733f, NSPS J

DHT	DHT fuel gas drum	Fuel gas H_2S	OAC 780b
SRU #1	SRU #1 incinerator stack	SO_2	OAC 733f, NSPS J, NESHAP UUU
SRU #2	SRU #2 incinerator stack	SO_2	OAC 908c, NSPS J, NESHAP UUU
Boiler #1	Boiler stack	NO_X, O_2	OAC 578b, NSPS Db
Boiler #4	Boiler stack	NO_X, CO, O_2	OAC 877b, NSPS Db
Flare	Flare	H_2S, TRS	NSPS Ja

The CEMS quality assurance reports which document drift, out of control periods, and the results of relative accuracy test audits (RATA) and cylinder gas audits (CGA) are to be reported on a quarterly basis. To satisfy this reporting requirement, Phillips 66 updates this information in the monthly air reports.

If the CEMS is mandated by NSPS or MACT, it must comply with the requirements in the applicable subpart along with the referenced terms in NSPS Subpart A (§60.13) or in MACT Subpart A (§63.8). The respective Subpart A lists general CEMS installation, operation, and QC/QA requirements. The specific subpart (e.g., NSPS Subpart J, MACT Subpart UUU) mandates the specific QA/QC thresholds and references the pollutant-specific Performance Specifications (PS) under 40 CFR 60 Appendix B for installation and initial evaluation and 40 CFR 60 Appendix F for the ongoing quality control and quality assurance.

In the case of NSPS Subpart J and MACT Subpart UUU, they can apply to the same pollutant, and both require a CEMS to demonstrate compliance (i.e., CO for FCCU, SO_2 for SRU). As such, Subpart UUU has an overlap provision that generally aligns the requirements with those in Subpart J to simplify compliance.

In addition, all CEMS installed in the NWCAA jurisdiction must also comply with NWCAA 367 which references NWCAA Appendix A (formerly referred to as NWCAA 365, 366 and the "Guidelines for Industrial Monitoring Equipment and Data Handling"). Note that NWCAA 365 and 366 are federally enforceable (i.e., are included in the SIP). NWCAA 367 and NWCAA Appendix A were adopted on July 14, 2005; the new regulations are "State Only" until incorporated into the State Implementation Plan.

NWCAA Appendix A references the 40 CFR 60 Appendix B Performance Specifications for CEMS installation requirements and 40 CFR 60 Appendix F for ongoing operation. It also explicitly lists certain operating requirements (e.g., calibration; maintenance; auditing; data recording, validation, and reporting).

Generally, the calibration drift (zero and span) for each CEMS must be checked daily and data accuracy assessments must be performed at least once every calendar quarter. This entails that a relative accuracy test audit (RATA) must be performed once per year and cylinder gas audits (CGAs) performed once during each of the other calendar quarters. Data recorded during periods of CEMS breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages. Pursuant to NWCAA Appendix A III(F)(14), CEMs are required to maintain greater than 90% data availability monthly.

In addition, CEMS performance is required to be submitted to NWCAA monthly. A large part of the monthly report includes information about the duration and nature of CEMS downtime, changes made to the CEMS, total operating time and dates of CEMS audits or certifications. In addition, the monthly report includes disclosure of deviations from required monitoring and exceedances of emission limits.

3.11 Visible Emissions

Monitoring, recordkeeping, and reporting (MR&R) requirements for compliance with visible emission standards found in State and NWCAA regulations or contained in OACs for various emission units around the refinery have been consolidated in AOP Section 6.1, unless otherwise specified in the term. These standards were gap-filled by NWCAA as the standards themselves did not contain sufficient monitoring to reasonably assure compliance.

For combustion units firing gaseous fuels, NWCAA requires Phillips 66 to conduct and record monthly qualitative observations of the refinery combustion unit stacks. If visible emissions are observed, Phillips 66 must reduce the opacity to zero, or take certified opacity readings using Method Ecology 9A within 24 hours of observing the visible emissions and daily thereafter until opacity is shown to be less than the applicable standard. Visible emission exceedances measured using Method Ecology 9A must be reporting in monthly deviation reports. Visible emissions are considered to be in excess of the applicable opacity limit if a certified reading is not taken on the mandated schedule.

The observation frequency may be reduced to quarterly if no visible emissions are observed for six consecutive months. If any visible emissions are noted during the observation, the frequency shall revert to monthly observations of individual stacks.

The only units at the refinery that fire oil are the various emergency generators. Because the emergency generators only operate sporadically and are typically not regulated under NSR, an explicit ongoing compliance demonstration is deemed to be not necessary.

3.12 Performance Tests

Each year, stack tests at refinery emissions units are performed to determine compliance with emission limits and standards found in Orders of Approval to Construct (OAC) issued by NWCAA, PSD permits issued by Ecology, and as part of New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements. Table 3-13 contains information on the most recent tests performed during the last air operating permit term.

Table 3-15 Performance Test Summary

Fluid Catalytic Cracking Unit (FCCU)					
Date	**Pollutant**	**Requirement**	**Limit**	**Result**	**Frequency**
8/14/2021	PM	PSD-00-02 CAM 40 CFR 60 Subpart J	0.5 lb/1,000 lb coke	Pass	Annual
8/14/2021	NH3	OAC 1047a	10 ppm @ 0% O_2	Pass	Annual
Vacuum Tower					
11/2/2021	NH3	OAC 1012e	10 ppm @ 7% O_2	Pass	Annual
CGD/S-Zorb Heater					
3/9/2021	NOX	PSD-00-02	17 ppm @ 0% O_2		Annual
			5.1 tpy		
3/9/2021	CO		0.0824 lb/MMBtu		Annual
			14.4 tpy		
Tier III/LSR Heater					
4/17/2019	NOX	OAC 1223	0.035 lb/MMBtu		3 years
4/17/2019	CO	OAC 1223	0.030 lb/MMBtu		3 years
DHT Heater					
10/21/2018	NOX	OAC 780b	0.05 bl/MMBtu	Pass	CTM-034 Annual EPA Method 19/7E 5 years
SRU #1					
3/1/2022	NOX	PSD-00-02	42.2 ppm @ 7% O_2		Annual
			9.9 tpy		
3/1/2022	CO	PSD-00-02	57.1 ppm @ 7% O_2		Annual
			8.30 tpy		
SRU #2					
3/3/2022	NOX	PSD-05-01	42.2 ppm @ 7% O_2		Annual
			2.3 lb/hr		
3/3/2022	CO	PSD-05-01	57.1 ppm @ 7% O_2		Annual

			1.9 lb/hr		
Truck Gasoline Loading Rack					
3/20/2020	VOC	OAC 265a, NSPS XX, NESHAP R	35 mg/liter		biennial

Based on communication between the NWCAA and Phillips 66 in January and February 2019, the MACT requirement, in 40 CFR §63.7540(a)(10), to conduct tune-ups on heaters and boilers every 61 months, will be decreased to every 13 months. This will ensure sufficient evidence to determine that Phillips 66 is meeting the MACT requirement to maintain heater O_2 above the level at which the tune-up was performed.

4 Process Descriptions, Construction History, and Regulatory Applicability

The following section provides a description of each refinery process area along with a construction history and regulatory applicability discussion. The refinery areas are presented in the same order found in the AOP for ease in cross-referencing. The construction history details how and why specific requirements were applied during the NSR permitting. In general, one-time only conditions that have been met are not discussed because they are not considered part of on-going compliance requirements for the facility. If a specific term in the AOP is clear and consistent with the underlying term, it is not discussed further in the Statement of Basis. However, terms where gap-filling has occurred, a regulatory interpretation has been made, or where the level of regulatory complexity warrants clarification are discussed in this section.

4.1 Crude Distillation Process Area

4.1.1 General Operation and Background

The Crude Distillation Process Area includes the crude distillation tower and a straight run gasoline plant. Together they are commonly referred to as the Crude Unit (Figure 4-1).

The Crude Unit separates the crude oil feedstock, consisting of a mixture of hydrocarbons, into its various components by boiling point temperature ranges or "cut point." Heat is supplied to the bottom of the distillation tower while cooler product is recycled or "refluxed" back into the top of the tower. This heating and cooling creates a temperature gradient across the tower. The crude oil is continuously vaporized and condensed throughout the tower. Collection trays are positioned at various levels in the tower to collect and remove liquid product of a particular boiling point or cut.

The crude unit process varies depending on the characteristics of a specific crude oil. Different crude oils require different heat loads for processing and produce different quantities of the various cuts. Various additives are used to control operating parameters such as pH, and to inhibit corrosion.

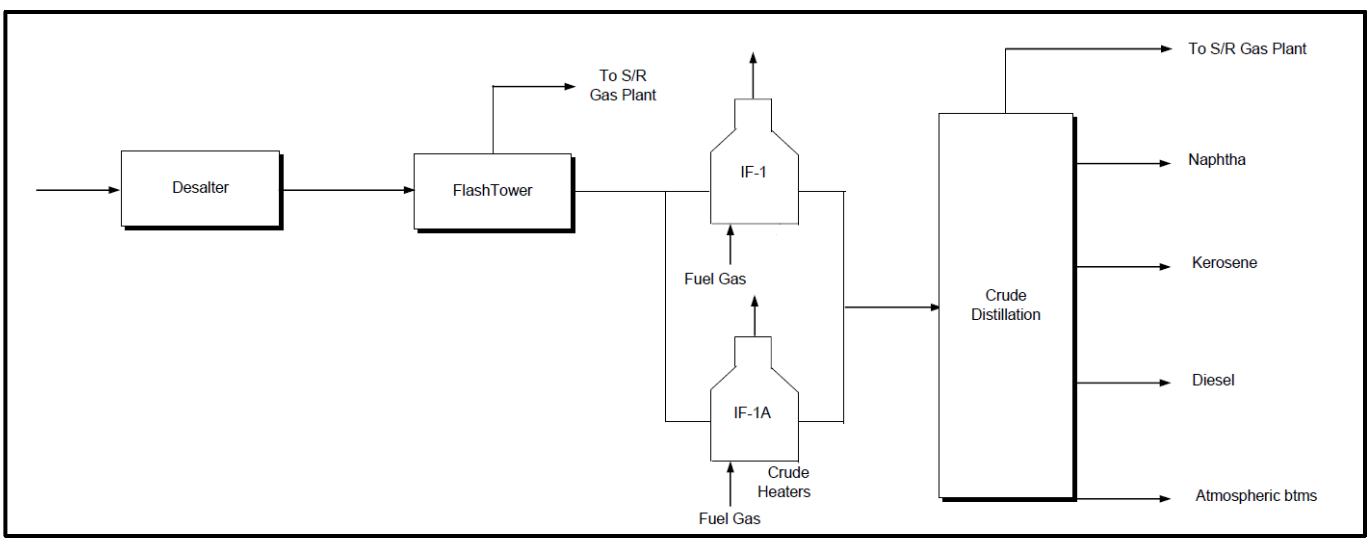

Figure 4-1 Crude Distillation Process

The distilled gasoline cut is further processed in towers at the straight run gas plant prior to becoming a gasoline blending component (Figure 4-2). The naphtha range cut is sent to the reformer and the kerosene cut is either sent to storage or processed further. The diesel cut is sent to storage or processed in the DHT Unit. The atmospheric bottoms are sent to the FCCU for processing into fuel oil and gasoline blending components. These units will be discussed further in this section below.

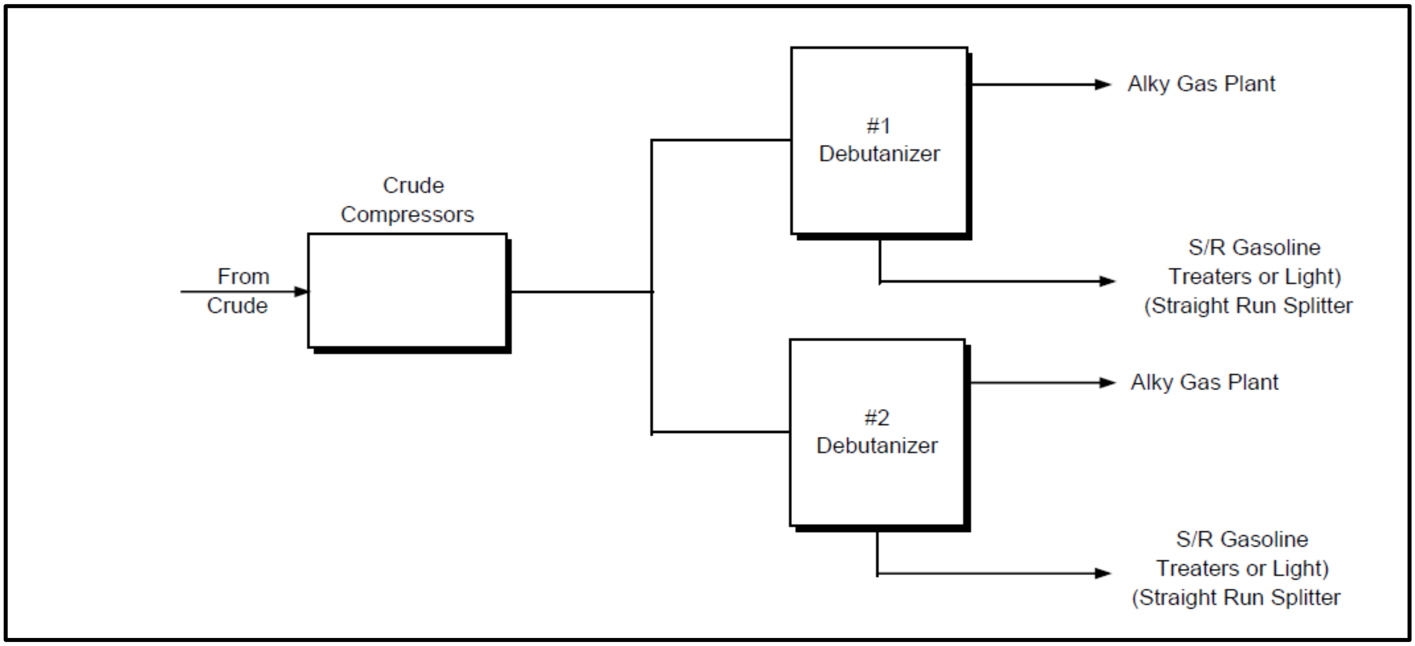

Figure 4-2 Straight Run Gas Process

Volatile organic compounds and hazardous air pollutants are emitted from the Crude Unit from leaking equipment components such as valves, pumps, flanges, and compressors. There are two heaters in the Crude Unit that supply heat for distillation: the Crude Heater (1F-1) and Supplemental Crude Heater (1F-1A). These heaters emit products of combustion. There are also fugitive emissions from oily wastewater drains and sewers located in the Crude Unit.

4.1.2 Construction and Permitting History

The basic configuration of the units in the Crude Distillation Process Area was established during the original refinery construction in 1953. On January 24, 1972, NWCAA issued OAC 24 approving construction of a new Supplemental Crude Heater (1F-1A). On April 12, 1979, the NWCAA issued OAC 235 approving construction of the Combustion Air Preheater for the Crude Heater (1F-1). Both OAC 24 and OAC 235 are considered narrative with no applicable requirements and are not included in the AOP.

There were two projects approved by both NWCAA and the WDOE that included changes at the Crude Unit. The Ferndale Upgrade/Clean Fuels project, permitted in 2001 under OAC 733 and PSD-00-02 approved new FCC and CGD process units. The project also included various modifications to process units including modifications to the #2 Hydrofiner located in the Crude Distillation Processing Area. The #2 Hydrofiner was later decommissioned to make room for the Tier III Hydrotreater Unit, approved under OAC 1223. The PSD permit has been revised eight times to its current version, PSD-00-02 Amendment 8 issued September 15, 2015. PSD-00-02 Amendment 8 does not include any requirements for equipment in the Crude Distillation Process Area.

The second, dual permitted project was the Crude/Fluidized Catalytic Cracking/Sulfur Recovery Unit project. This project was approved in 2005 under OAC 908 and PSD-05-01. The project included modifications to increase the crude oil charge rate at the Crude Unit from 98,000 barrels per day to 105,000 barrels per day. The Crude Unit was modified with new piping, a new heat exchanger, new nozzles in the distillation column, and new trays in the crude and preflash columns. The current versions of these approval orders, OAC 908b and PSD-05-01, do not contain any applicable requirements for equipment at the Crude Unit.

In 2011, NWCAA approved projects to reduce fouling and corrosion in heat exchangers in the Crude Unit under OAC 1108. In 2016, NWCAA approved a project in the Crude Distillation Process Area to replace the crude distillation tower. This project was approved under OAC 1232 and involved a replacement of the main crude distillation tower with a new tower.

The following is a summary of NSR approvals affecting the Crude Distillation Process Area.

NWCAA Order of Approval to Construct 733f - Ferndale Upgrade/Clean Fuels Project

Original issuance April 6, 2001. Revised August 13, 2002, June 8, 2005, July 29, 2005, August 2, 2012, September 30, 2016, and December 10, 2019.

OAC 733 originally approved modifications to the #2 Hydrofiner at the Crude Unit. However, the #2 Hydrofiner has been decommissioned. During revisions OAC 733c and OAC 733d, the approval order was revised to include Consent Decree obligations so that they were federally enforceable requirements. These requirements include making the two heaters in the Crude Unit subject to 40 CFR 60 Subpart J limiting the amount of H_2S in the fuel gas combusted in those heaters. Another requirement restricts those heaters from combusting fuel with a sulfur content greater than 0.05% by weight. These Consent Decree based requirements in OAC 733f are listed in the AOP. OAC 733e Conditions 19 and 20 include Consent Decree requirements for two heaters that were in the Crude Unit: No. 2 HDF Heaters 14F-1 & 2. These HDF heaters were part of the #2 Hydrofiner that was decommissioned. The HDF heaters have been removed as part of the Tier III Hydrotreater project constructed under OAC 1223. Revision 733f cleaned up the OAC for incorporation into this AOP renewal and provided for SS&M flexibility at SRU #1.

NWCAA Order of Approval to Construct 1108 – Projects to Reduce Fouling and Corrosion in Heat Exchangers

Original issuance December 8, 2011. No revisions.

OAC 1108 approved four linked projects designed to reduce fouling and corrosion in heater exchangers to optimize operations between maintenance turnaround cycles. The project added equipment components at the Crude, FCCU and Alkylation Units. OAC 1108 contains a startup notice and no ongoing applicable requirements. The startup notice was received on May 7, 2012, in a letter stating that the process units were restarted on April 25, 2012, following completion of the project. This one-time only requirement has been completed. Because there are no ongoing applicable requirements, OAC 1108 is not listed in the AOP.

NWCAA Order of Approval to Construct 1232 – Replace the Crude Distillation Tower

Original issuance February 11, 2016. No revisions.

OAC 1232 approved a project to replace the crude distillation tower with a new tower. The project involved new equipment components at the new tower offset by a reduction in components being removed by decommissioning of the old tower. On April 7, 2017, the NWCAA received a notice from the refinery that the new crude distillation tower began operating on March 27, 2017. This notice completed the one-time only requirement in OAC 1232 Condition 1 to provide the notice. Therefore, Condition 1 is not included in the AOP.

4.1.3 Regulatory Applicability

Refinery fuel gas combusted in the two process heaters at the Crude Unit is required to meet the NSPS Subpart J standard for H_2S concentration in the fuel gas, and periodic tune-ups are required for each heater under the Boiler MACT. There are miscellaneous process vents in the Crude Unit subject to Refinery MACT provisions. Equipment components, including two reciprocating compressors (1K-1 and

1K-1A), at the Crude Unit are under the leak detection and repair (LDAR) program required by NSPS and Refinery MACT standards.

4.2 Catalytic Cracking Process Area

4.2.1 General Operation and Background

The Catalytic Cracking process area includes the Fluidized Catalytic Cracking Unit (FCCU), the Vacuum Distillation Tower, the Vacuum Flasher Heater (4F-2), the Unsaturated Gas Plant (Unsat Gas Plant) process unit, the Carbon Monoxide (CO) Boiler and the Flue Gas Scrubber (FGS). The entire process area is commonly referred to as the FCCU or FCC Unit.

The FCCU takes heavier cuts of the crude oil, such as gas oil and residual oil, from the Crude Unit and converts them into lighter cuts of higher value products, such as olefins and gasoline, by using a catalyzed high temperature reaction to break apart the hydrocarbon bonds (Figure 4-3). The catalytic reaction occurs in the riser section of the FCCU. Coke, formed during the reaction, adheres to the catalyst reducing the effective area of the catalyst. The coke is removed from the catalyst by combustion in the Regenerator, often under sub stoichiometric conditions. The carbon monoxide rich Regenerator flue gas is then combusted in the CO Boiler, where utility steam is generated for the refinery. Sulfur dioxide and particulate matter in the CO Boiler exhaust gas are removed by a wet gas scrubber, commonly referred to as the flue gas scrubber (FGS).

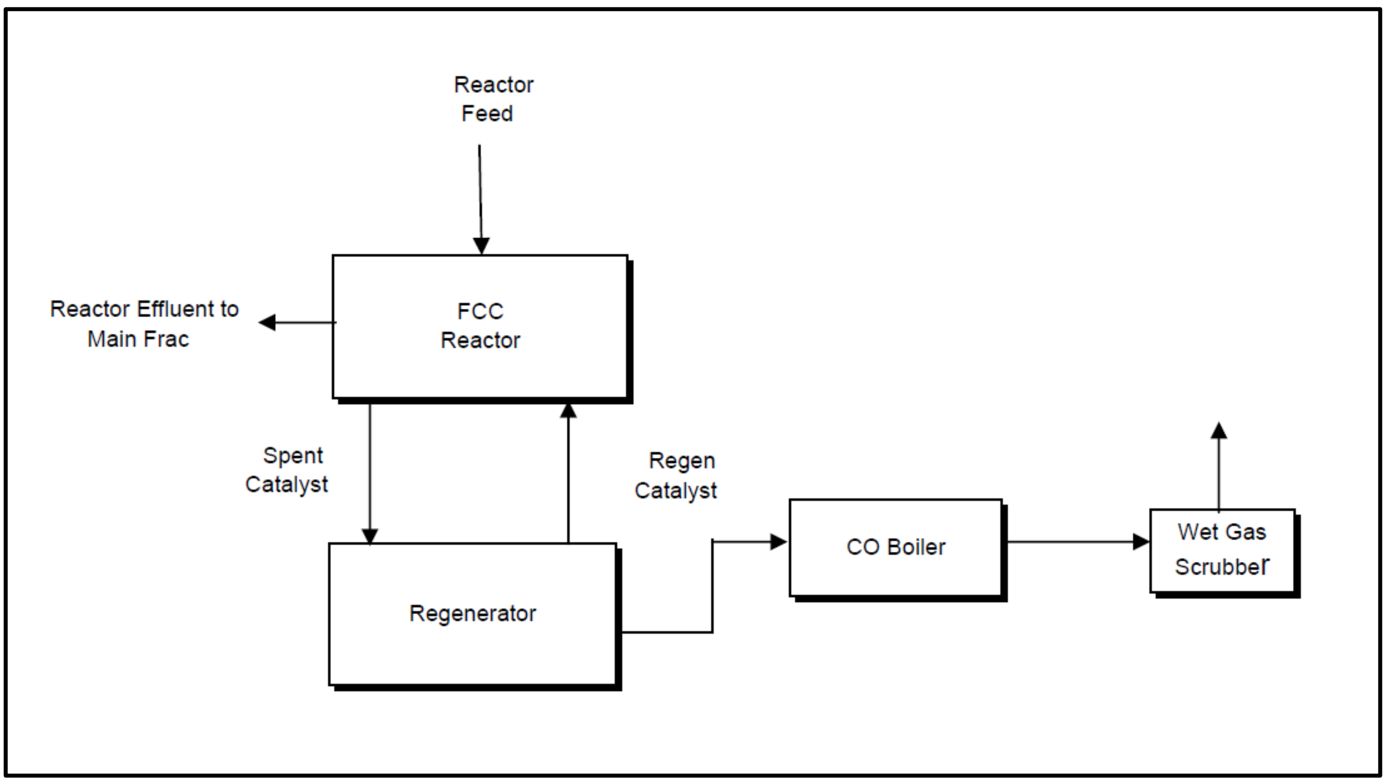

Figure 4-3 FCCU Process

The Vacuum Distillation Tower takes crude distillation bottoms and further distills the material to produce a fuel oil blending component and additional feed for the FCCU (Figure 4-4).

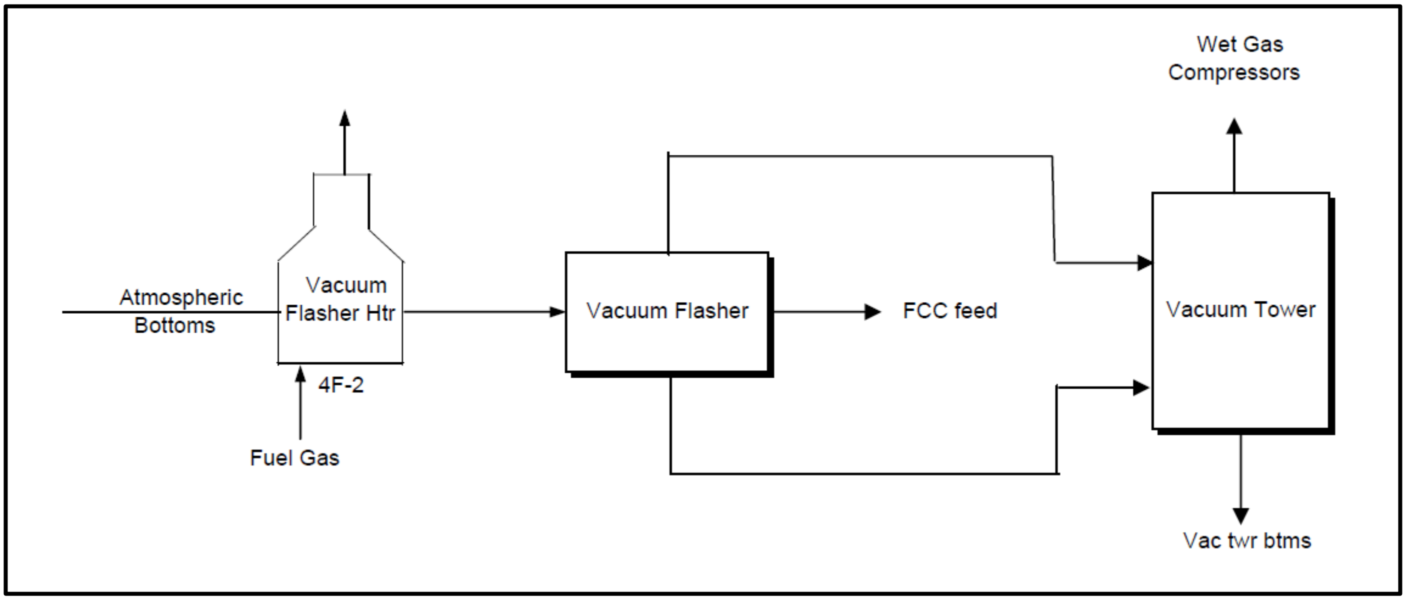

Figure 4-4 FCCU Feed Prep Process

Lighter hydrocarbons from the FCCU are processed in the Unsaturated Gas Plant process unit where absorber columns remove sulfur compounds (such as H_2S) from the light gases (Figure 4-5). The sulfur compounds are then sent to the Sulfur Recovery Plant for recovery.

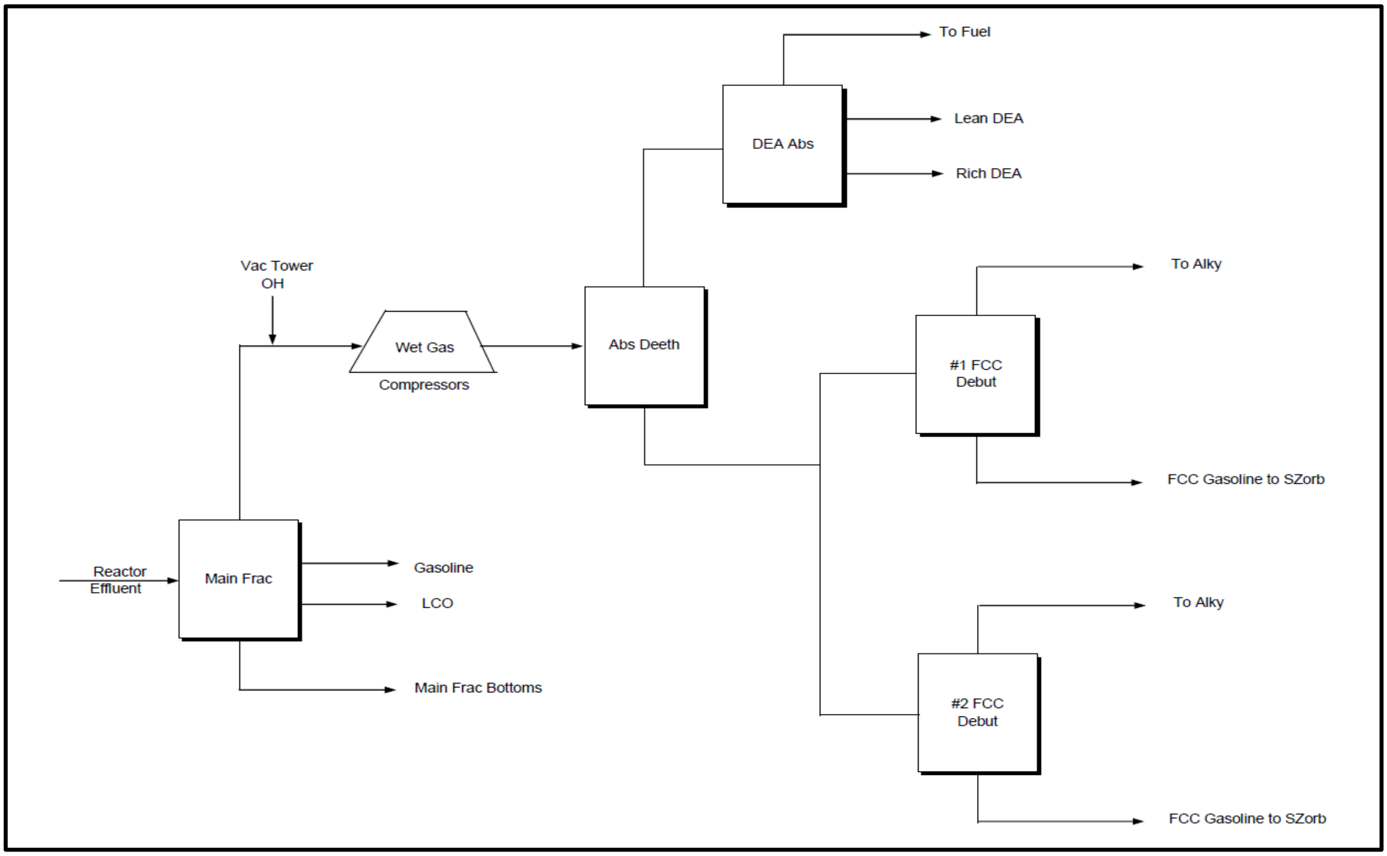

Figure 4-5 FCCU Gas Plant Process

Emissions from FCCU catalytic regeneration and from the CO Boiler are controlled by the FGS before being discharged to the atmosphere. A second point source of emissions is from the Vacuum Flasher Heater (4F-2) stack. The FCCU includes one miscellaneous process vent (#25-FV-007) regulated under 40 CFR 63 Subpart CC as a Group 1 vent that is controlled by the flare gas recovery system and flare. There are also two Group 2 miscellaneous process vents at the FCCU that are used to vent the cases of wet gas compressors 5K-1 and 5K-1A. These Group 2 vents are not required to be controlled under Subpart CC. There are also fugitive emissions from equipment components in VOC and HAP service at the FCCU.

4.2.2 Construction and Permitting History

The Catalytic Cracking Process Area was constructed with refinery construction in 1953. This process area originally included a Thermofor Catalytic Cracking Unit (TCCU) that has subsequently been replaced. The following is a list of construction projects at the Catalytic Cracking Process Area that have received approvals from the NWCAA, and in some cased approval from WDOE in the form of PSD permits. Approvals that include applicable requirements at the Catalytic Cracking Process Area are described in more detail below. Those that do not include any applicable requirements at the Catalytic Cracking Process Area are described herein.

In 1981, the NWCAA approved a project to install a combustion air preheater on the Tar Separator Heater (4F-2) under OAC 340. The Tar Separator Heater is now referred to as the Vacuum Flasher Heater(4F-2). OAC 340 was superseded by OAC 1012 issued on February 7, 2008, approving installation of SCR on the Vacuum Flasher Heater (4F-2). The SCR reduces NOx emissions from the heater as an obligation of the Consent Decree. OAC 1012 has been revised five times to OAC 1012e.

Revsion 1012c added requirements listed in the Consent Decree for termination purposes of the decree. Revision 1012d added a provision allowing the heater to operate without SCR during maintenance and revision 1012e revised the source testing requirements from 90% of the heater duty to normal operating conditions during testing; this was issued May 24, 2018.

In 1990, the NWCAA approved the Refinery Optimization Project under OAC 288. The OAC was administratively revised to OAC 288a on June 9, 2016. The Refinery Optimization Project involved modifications to the Thermofor Catalytic Cracking Unit (TCCU) including new distillation trays, higher cracking severity and an increase in the steam production capacity of the CO Boiler. OAC 288a has no applicable requirements and is not included in the AOP.

In 1994, the NWCAA approved construction of a Liquid Feed Heater in the Catalytic Cracking Process Area under OAC 523 issued December 5, 1994. The 101 MMBtu/hour Liquid Feed Heater was constructed to pretreat gas oils from the Vacuum distillation and Crude distillation towers prior to feed into the Thermofor Catalytic Cracker. OAC 523 was revised to OAC 523a on December 16, 1998. The Liquid Feed Heater was decommissioned as part of the Ferndale Upgrade/Clean Fuels Project.

In 2001, the Ferndale Upgrade/Clean Fuels Project was approved by NWCAA under OAC 733 and by the WDOE under PSD-00-02. The project involved replacing the Thermofor Catalytic Cracking Unit (TCCU) with the current Fluidized Catalytic Cracking Unit (FCCU). The associated CO Boiler was also replaced. The project did not change the nominal feed rate to the unit of 30,000 barrels per day. The new FCCU included a 70 MMBtu per hour combustion air heater used during FCCU startups. The new CO Boiler was equipped with auxiliary fuel fired burners to assist in CO combustion and for producing additional steam at the CO Boiler. All exhaust from the FCCU is routed through the CO Boiler so that emissions discharged from the CO Boiler include those from the FCCU combustion air heater, the FCCU regenerator, CO combustion in the CO Boiler, and auxiliary fuel burning in the CO Boiler. Exhaust from the CO Boiler is controlled by a Belco Technologies Corporation EDV® wet flue gas scrubber before discharging to the atmosphere. This scrubber is commonly referred to in the AOP as the CO Boiler flue Gas Scrubber (FGS). The current versions of OAC 733 and PSD-00-02 have applicable requirements for equipment in the Catalytic Cracking Process Area and these approval orders are described in more detail below.

In 2005, the Crude/FCCU/SRU Upgrade Project was approved by the NWCAA under OAC 908 and by the WDOE under PSD-05-01. The project involved modifications to increase the charge rate of the FCCU to 36,500 barrels per day. This was accomplished by modifying the FCCU gas plant by replacing fractionator trays with packing, installing an additional column in the gas plant to separate the absorber deethanizer tower into two, replacing the off-gas absorber with a larger tower, replacing the regenerator trays with packing, and adding another rich amine flash drum. The current versions of OAC 908 and PSD-05-01 have no applicable requirements for equipment in the Catalytic Cracking Process Area.

In 2009, a project was approved under OAC 1047 to install an enhanced selective non-catalytic reduction (ESNCR) system on the CO Boiler to reduce NOx emissions as an obligation of the Consent Decree. OAC 1047 has been revised to OAC 1047a. OAC 1047a includes applicable requirements for the Vacuum Flasher Heater and is described in more detail below.

On December 8, 2011, a project was approved under OAC 1108 to reduce fouling and corrosion in heat exchangers at the FCCU and other process units to optimize operations between maintenance turnaround cycles. OAC 1108 contains a startup notice but no ongoing applicable requirements. The startup notice was received on May 7, 2012, in a letter stating that the process units were restarted on April 25, 2012, following completion of the project. This one-time only requirement has been completed. Because OAC 1108 has no ongoing requirements, it is not included in the AOP.

On July 14, 2014, NWCAA Compliance Order No. 13 became effective after mutual signatures by Phillips 66 and NWCAA to memorialize Consent Decree obligations. A summary of this order is included following the NSR orders because it establishes short-term and long–term CO limits at the FCCU.

The following is a summary of NSR approvals and Compliance Order No. 13 affecting the Catalytic Cracking Process Area.

NWCAA Order of Approval to Construct 733f - Ferndale Upgrade/Clean Fuels Project

Original issuance April 6, 2001. Revised August 13, 2002; June 8, 2005, July 29, 2005, August 2, 2012, September 30, 2016, December 10, 2019.

OAC 733 approved FCCU construction in 2001. The previous version of this approval, OAC 733e, had numerous conditions that are considered ongoing requirements for equipment at the Catalytic Cracking Process Area. All these requirements are listed in the AOP. Some noteworthy requirements from OAC 733e are described below.

During revisions OAC 733c and OAC 733e the approval order was revised to include Consent Decree obligations making them federally enforceable requirements. These requirements include making the Vacuum Flasher Heater located in the Catalytic Cracking Process Area subject to 40 CFR 60 Subpart J limiting the amount of H_2S in the fuel gas combusted in the heat. Another requirement restricts the heater from combusting fuel with a sulfur content greater than 0.05% by weight. These Consent Decree based requirements are listed in the AOP. Another Consent Decree requirement in OAC 733e for equipment at the FCCU was Condition 21 requireing an alternative monitoring plan (AMP) be in place instead of monitoring opacity with a continuous opacity monitoring system (COMS) on the FCCU/CO Boiler FGS stack as explicitly required by 40 CFR 63 Subpart UUU. The AMP was needed because flue gas water, condensing in the FGS stack, make it impractical to operate a COMS. EPA approved the AMP dated December 7, 2009. OAC Condition 21 allows the NWCAA to formally include the AMP requirement in the AOP as a specifically applicably requirement.

OAC 733e Condition 9 requires a visual opacity limit of 20% on the CO Boiler FGS stack. Ongoing compliance monitoring has been gap-filled using the alternative monitoring plan (AMP) prescribed in OAC 733e Condition 21. This has been done because there may be a visible plume from the stack, and it would be impractical to use the commonly referred to visual monitoring method described in Section 6 of the AOP. This AMP has also been used as a gap-filled monitoring method for opacity limits on the FGS stack established under the SIP-versions of WAC 173-400-040 and NWCAA Section 451. In addition, this AMP has also been used as a gap-filled monitoring method for the PM limits related to the FCCU regenerator burn-off rates under 40 CFR 6 Subpart UUU.

OAC 733e included a limitation on annual capacity factor for combusting natural gas in the CO Boiler as supplemental fuel providing a federally enforceable method to exempt the CO Boiler from the NO_X limit of 40 CFR 60 Subpart Db. Revision 733f cleaned up the OAC for incorporation into the AOP renewal and provided for SS&M flexibility at SRU #1.

NWCAA Order of Approval to Construct 1012e - Installation of SCR on the Vacuum Flasher Heater

Original issuance February 7, 2008. Revised September 11, 2008, April 27, 2009, June 7, 2012, April 21, 2015, and May 24, 2018.

OAC 1012 approved installation of a selective catalytic reduction (SCR) system on the Vacuum Flasher Heater (4F-2) to control NOx emissions. This heater was previously named the Tar Separator Heater. The OAC provides federally enforceable limits on NOx as required by the Consent Decree. The first revision to the OAC changed the NO_X averaging period from 12 months to 365 days consistent with the limit in the Consent Decree. The second revision relaxed the NO_X limit from 12 ppm to 80 ppm, and from 0.011 lb/MMBtu to 0.07 lb/MMBtu, because the SCR did not operate as efficiently as planned after installation. The third OAC revision added a 189 MMBtu/hour heat input limit for the heater for Consent Decree purposes. The fourth revision, OAC 1012d, provided a 336 hour per year period for the heater to operate without SCR to facilitate maintenance and repair activities. The last revision modified Condition 5 to allow source testing under operating rates instead of 90% of the heater's firing capacity.

All of conditions of OAC 1012e are included in the AOP. Condition 3 includes a visible emissions limit of 5% opacity for the Vacuum Flasher Heater using WDOE Method 9A. This condition does not include ongoing MR&R to determine compliance. The NWCAA added a gap-filled requirement to periodically check for compliance using a refinery-wide visual emissions monitoring program listed in Section 6 of the AOP.

NWCAA Order of Approval to Construct 1047a – Installation of ESNCR on the CO Boiler

Original issuance December 18, 2009, and revised October 21, 2014.

OAC 1047 approved a project to install enhanced selective non-catalytic reduction (ESNCR) on the CO Boiler to reduce NOx emissions. The ESNCR system functions by injecting vaporized ammonia enhanced with hydrogen into the combustion chamber of the CO Boiler. The ammonia reacts with nitrogen oxide (NO_X) in the combustion zone converting it to gaseous nitrogen (N_2). The NOx reductions were required by the Consent Decree and the associated federally enforceable requirement under PSD-00-02 Amendment 7 and its subsequent revisions. The original OAC 1047 required that ESNCR be used at all times. The OAC was revised to OAC 1047a removing the provision to operate ESNCR at all times because the refinery can meet the NOx limits of PSD-00-02 without ESNCR when the FCCU is operating in full combustion mode.

The conditions of OAC 1047a have been included as applicable requirements in the AOP.

WDOE Prevention of Significant Deterioration (PSD) Permit PSD-00-02 Amendment 8 - Ferndale Upgrade/Clean Fuels Project

Originally issued April 4, 2001. Revised eight times to current Amendment 8 issued September 9, 2015.

Similar to OAC 733, PSD-00-02 approved construction of the FCCU in 2001. The current version, PSD-00-02 Amendment 8, has numerous conditions that are considered ongoing requirements for equipment at the Catalytic Cracking Process Area. All these requirements are listed in the AOP except as noted below.

Condition 13 requires an initial NOx source test on the FCCU/CO Boiler. Initial testing was conducted in June 2003 demonstrating compliance with the applicable NOx limits in place at that time. This one-time only requirement has been completed and is not listed in the AOP.

Condition 20 requires that the project commence construction within 18 months of PSD-00-02 issuance. The refinery commenced construction of the project within 18 months. Condition 20 is considered obsolete and not included in the AOP.

Condition 21 is a PSD permit appeal provision. The 30-day timeline for appealing the PSD permit has expired. Condition 21 is considered obsolete and is not included in the AOP.

NWCAA Compliance Order No. 13 – Consent Decree CO limits for the FCCU.

Compliance Order No. 13 became effective July 14, 2014, implementing Consent Decree obligations at the FCCU including a carbon monoxide limit of 500 ppm, 1-hour average, and a 100 ppm limit using a 365-day average, with both concentration values corrected to 0% oxygen. The order exempts compliance with the 1-hour CO limit during periods of startup, shutdown, and malfunction if good air pollution control practices are used. Compliance with the CO limit is continuously demonstrated with a CEMS. This order has been incorporated into the AOP. It is noted that PSD-00-02 has similar CO limits but does not provide exemptions for startup, shutdowns, and malfunctions.

4.2.3 Regulatory Applicability

Refinery fuel gas combusted in the FCCU Combustion Air Heater, Vacuum Flasher Heater and used as supplemental fuel in the CO Boiler is required to meet the NSPS Subpart J standard for H_2S concentration in the fuel gas. Periodic tune-ups are required on the Vacuum Flasher Heater under the Boiler MACT. There are miscellaneous process vents in the FCCU subject to Refinery MACT provisions. Equipment components at the FCCU are under a leak detection and repair (LDAR) program required by NSPS and Refinery MACT standards.

The FCCU Regenerator and CO Boiler emit through a common stack; and therefore, are subject to a variety of local, state, and federal requirements as summarized below.

- Visual emissions (VE): NWCAA 451 (40% opacity, Method 9A), OAC 733f (20% opacity, Method 9), 173-400-040 (40% opacity, Method 9A), NSPS Subpart J (30% opacity, Method 9), MACT Subpart UUU (20%, 3-hour, 30%, 6-minute, Method 9).

Visual emissions from the FCCU and CO Boiler are controlled by a wet flue gas scrubber (FGS). The FGS has a condensing moisture laden plume that makes it difficult to take visual opacity observations. Therefore, the AOP prescribes ongoing compliance with these visual emission standards by monitoring the operating parameters of the FGS consistent with the EPA alternative monitor plan for opacity incorporated into OAC 733f.

- Particulate matter (PM): PSD-00-02 (0.50 lb/1000 lb coke burn-off and 0.020 gr/dscf) and NSPS Subpart J (2.0 lb/1000 lb coke burn-off), MACT Subpart UUU (1.0 lb/1000 lb coke burn-off).

PM emissions from the FCCU and CO Boiler are controlled by a wet flue gas scrubber (FGS). Compliance with PM limits are determined by annual source testing supplemented by monitoring the operating parameters of the FGS consistent with the EPA alternative monitor plan incorporated into OAC 733f.

- Sulfur dioxide (SO_2): OAC 733e (90% reduction and 50 ppmvd, 24-hour, and 95% reduction and 25 ppmvd, 365-day), NSPS Subpart J (90% reduction or 50 ppmvd, 7-day).

SO_2 emissions from the FCCU and CO Boiler are controlled by a flue gas scrubber (FGS) equipped with caustic scrubbing. The concentration of SO_2 in the FGS stack is continuously monitored with a CEMS. The inlet to the FGS is also monitored with a CEMS to ensure ongoing compliance with the SO_2 reduction requirements. OAC 773f includes an exemption from the BACT based SO_2 limit of 25 ppmvd during periods of malfunction as those periods are defined in the NSPS General Provisions.

- Nitrogen oxides (NOx): PSD-00-02 (123.2 ppmvd, 7-day, 127 ppmvd, 30-day, 96.1 ppmvd, 365-day, 308.10 tpy)

Ongoing compliance is determined with a NOx CEMS in the FGS stack.

Carbon monoxide (CO): PSD-00-02 (500 ppmvd, 1-hour, 1000 ppmvd 356-day), NWCAA CO 13 (100 ppmvd 1-hour, 500 ppmvd 365-day), NSPS Subpart J (500 ppmvd, 1-hour), MACT Subpart UUU (500 ppmvd, 1-hour).

Ongoing compliance is determined with a CO CEMS in the FGS stack. The Refinery MACT includes an exemption from the MACT standard during periods of startup, shutdown, or hot standby by keeping the regenerator exhaust gas ≥ 1% oxygen.

- Ammonia (NH_3): OAC 1047a (10 ppmvd, 24-hour)

Ammonia emissions are generated as collateral emissions from controlling NOx from the FCCU using enhanced selective non-catalytic reduction (ESNCR). The ammonia slip from the ESNCR system is measured in the stack during annual source testing. Ongoing compliance is determined by monitoring parameters of the ESNCR and FCCU in accordance with the Ammonia Emissions Monitoring Plan developed by the refinery.

OAC 733f limits the amount of natural gas that can be used for auxiliary firing in the CO Boiler to less than 10% of its annual capacity. This natural gas limit is intended to exempt the CO Boiler the NO_X 0.2 lb per MMBtu standard in 40 CFR 60 Subpart Db.

The FCCU is subject to HAP control requirements under 40 CFR 63 Subpart UUU. Subpart UUU requires that the refinery develop and implement an operation, maintenance, and monitoring plan (OMMP) to ensure ongoing compliance with the emission standards of Subpart UUU. The OMMP must be submitted and approved by the agency prior to implementation. On June 30, 2016, the NWCAA received the OMMP dated “June 2016” for the FCCU. The NWCAA implicitly approves this plan as part of the 2017

AOP renewal process because the AOP terms requiring the OMMP refers to the June 2016 plan to determine ongoing compliance with Subpart UUU.

Section 63.1571(a)(6) of Subpart UUU requires an initial test of the FCCU stack for hydrogen cyanide (HCN) emissions. This performance test was completed on October 22, 2013, as documented in a letter from Phillips 66 to EPA Region 10 dated March 24, 2016. There is no emission limit for HCN in Subpart UUU. Because this one-time only requirement has been completed, it is not listed in the AOP.

4.3 Alkylation Process Area

4.3.1 General Operation and Background

The Alkylation process area includes three process units: the Alkylation Unit (Alky Unit), the Catalytic Gasoline Desulfurization Unit (CGD/S-Zorb Unit) and the Butane Isomerization Unit (Butamer). The Catalytic Gasoline Desulfurization Unit is referred in the more common vernacular in the AOP as the S-Zorb Unit.

In the Alky Unit, light hydrocarbon streams of olefins and isobutene from crude distillation and catalytic cracking are combined with a hydrogen fluoride (HF) catalyst to form alkylate, a valuable gasoline blending component (Figure 4-6). A debutanizer tower within the unit recovers mixed butane. The Alky Unit includes a S/R Gas Plant and a Sat Gas Plant. Mixed butane and light ends off the S/R Gas Plant and Butamer are processed in the Sat Gas Plant to produce propane, butane, and isobutane (Figure 4-7).

In the Butamer, mixed butanes and hydrogen are combined in a reactor with perchloroethylene to convert normal butane to isobutane. Non-condensable gases generated at the Butamer are amine scrubbed to reduce their H_2S content and sent to the main refinery fuel gas system.

In the CGD/S-Zorb Unit heavy gasoline cuts from catalytic cracking are treated to remove sulfur.

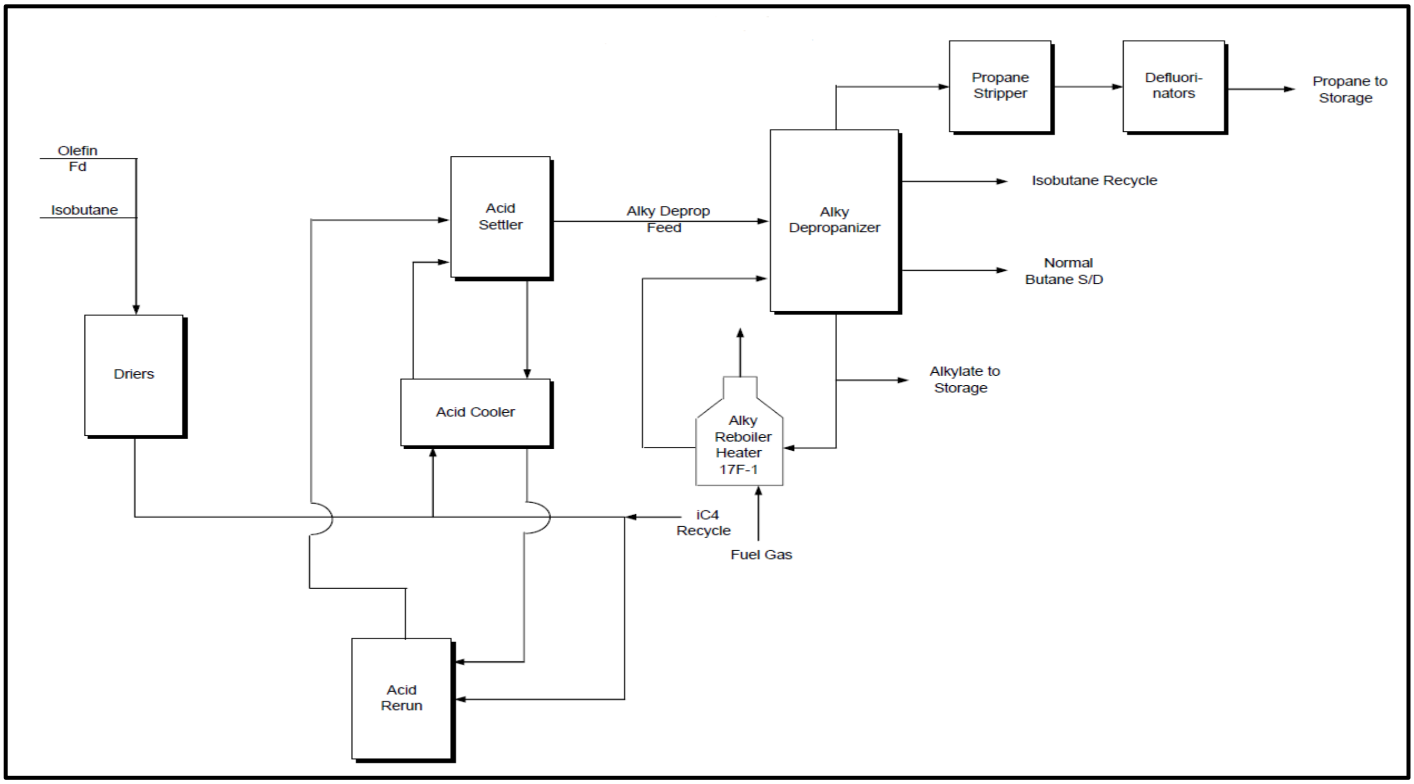

Figure 4-6 Alkylation Process

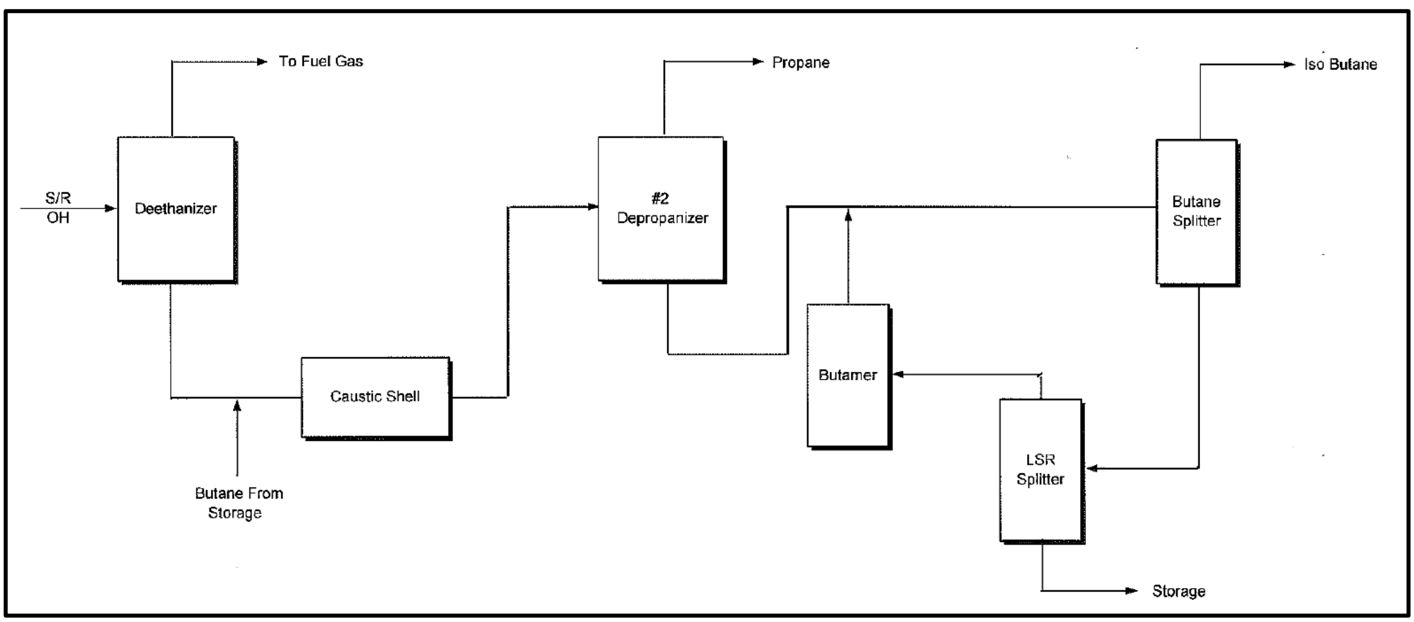

Figure 4-7 Alkylation Saturated Gas Plant Process

Emissions from Alkylation Process Area include emissions from the Alky Depropanizer Reboiler Heater and the S-Zorb Heater. There are miscellaneous process vents at the Alky Unit and fugitive emissions from equipment components in VOC and HAP service.

4.3.2 Construction and Permitting History

The original Alkylation Unit was constructed in 1965 and the Butamer was added in 1997. The Butamer required the addition of distillation equipment and new process sewers, but no process heater. The Cat Gas Desulfurizer Unit was added in 2001. This unit was originally designed with two process heaters. However, the CGD/S-Zorb Unit was constructed with a single heater and associated NSR permits were subsequently revised to reflect the change.

The following is a summary of NSR approvals affecting the Alkylation Process Area.

NWCAA Order of Approval to Construct 288a - Refinery Optimization Project

Original issuance June 18, 1990, and revised June 9, 2016.

The Refinery Optimization Project facilitated a capacity at the Crude Unit, TCCU and Alky Unit with modifications at each unit. The modification at the TCCU facilitated an increase in gasoline production by higher cracking severity. The TCCU, including the original CO boiler, was decommissioned and replaced with a FCCU and CO Boiler as approved under OAC 733 and PSD-00-02.

OAC 288a has no conditions and is therefore not cited under applicable requirements in the AOP.

NWCAA Order of Approval to Construct No. 564a – Construction of the Butamer

Original issuance August 30, 1996, and revised October 2, 2002.

OAC 564a has one condition requiring a LDAR program at the Butamer for equipment in perchloroethylene service. This condition is included in the AOP.

Perchloroethylene is a toxic air pollutant regulated under WAC 173-460 and t-BACT established under OAC 564 is LDAR. Perchloroethylene is also a HAP regulated under Refinery MACT. However, perchloroethylene is not a VOC.

NWCAA Order of Approval to Construct 715a - Refurbished Alky Splitter Tower

Original issuance December 3, 1999, and revised October 2, 2002.

OAC 715 approved a project to refurbish Splitter Tower 16C-304 within the Alky Unit. OAC 715a is considered narrative containing no applicable requirements and is not listed in the AOP. The OAC relies on federal requirements for equipment component leaks under NSPS Subpart GGG/VV and for controlling emission from process wastewater under NSPS Subpart QQQ, instead of establishing separate permit requirements as BACT.

NWCAA Order of Approval to Construct 733f - Ferndale Upgrade/Clean Fuels Project

Original issuance April 6, 2001. Revised August 13, 2002; June 8, 205, July 29, 2005, August 2, 2012, September 30, 2016, and December 10, 2019.

The Ferndale Upgrade/Clean Fuels project, permitted in 2001 under OAC 733 and PSD-00-02 (and subsequent revisions), approved construction of the CGD Unit located in the Alkylation Process Area. During revisions OAC 733c and OAC 733e the approval order was revised to include Consent Decree obligations so that they were federally enforceable requirements. These requirements included making the heater in the Alkylation Process Area, the Alky Depropanizer Reboiler (17-1), subject to 40 CFR 60 Subpart J limiting the amount of H_2S in the fuel gas combusted in that heater. Another Consent Decree related requirement restricted the Alky Depropanizer Reboiler (17-1) from combusting fuel with a sulfur content greater than 0.05% by weight. The Consent Decree based requirements in OAC 733e are listed in the AOP.

As BACT, OAC 733e limits SO_2 emissions from the S-Zorb Heater by limiting the H_2S content in the fuel gas and requires a LDAR program at the Alkylation Unit to minimize fugitive emissions from equipment component leaks. Revision 733f cleaned up the OAC for incorporation into the AOP renewal and provided for SS&M flexibility at SRU #1. All the requirements of OAC 733f applicable to equipment in the Alkylation Process Area are listed in the AOP.

NWCAA Order of Approval to Construct 795a – Construction of the Debutanizer Tower at the Alkylation Unit

Original issuance February 4, 2002, and revised June 9, 2016.

OAC 795 approved construction of the debutanizer tower at the Alkylation unit. The distillation tower assists in the recovery of butane from alkylate. The OAC was revised to OAC 795a as an administrative cleanup prior to incorporation into the AOP. OAC 795a has a single requirement for a LDAR program implemented in accordance with 40 CFR 60 Subpart VV with revisions specified in the OAC including lower leak definitions for pumps (2,000 ppm) and valves (1,000 ppm), and specific instrument monitor calibration and draft checks as BACT. This requirement has been incorporated into the AOP.

NWCAA Order of Approval to Construct 1108 – Projects to Reduce Fouling and Corrosion in Heat Exchangers

Original issuance December 8, 2011. No revisions.

OAC 1108 approved four linked projects designed to reduce fouling and corrosion in heater exchangers to optimize operations between maintenance turnaround cycles. The project added equipment components at the Crude, FCCU and Alkylation Units. OAC 1108 contains a startup notice and no ongoing applicable requirements. The startup notice was received on May 7, 2012, in a letter stating that the process units were restarted on April 25, 2012, following completion of the project. This one-time only requirement has been completed. Because there are no ongoing applicable requirements, OAC 1108 is not listed in the AOP.

NWCAA Order of Approval to Construct 1109 – MSAT Project to Reduce Benzene in Gasoline

Original issuance December 8, 2011. No revisions.

OAC 1108 approved a reconfiguration of the Crude Unit designed to reduce the benzene content of gasoline products to comply with the EPA Mobile Source Air Toxic (MSAT) Phase 2 rule. The project added equipment components at the Crude Unit. OAC 1109 contains a startup notice and no ongoing applicable requirements. The startup notice was received on May 7, 2012, in a letter stating that the Crude Unit restarted on April 25, 2012, following completion of the project. This one-time only requirement has been completed. Because there are no ongoing applicable requirements, OAC 1109 is not listed in the AOP.

WDOE Prevention of Significant Deterioration (PSD) Permit PSD-00-02 Amendment 8 - Ferndale Upgrade/Clean Fuels Project

Originally issued April 4, 2001. Revised eight times to current Amendment 8 issued September 9, 2015.

Similar to OAC 733, PSD-00-02 approved construction of the CGD Unit located in the Alkylation Process Area in 2001. The current version, PSD-00-02 Amendment 8 has numerous conditions that are considered ongoing requirements for equipment at the Alkylation Process Area. All these requirements are listed in the AOP except as noted below.

Condition 13 requires an initial NOx source test on the CGD/S-Zorb Heater. Initial testing was conducted in March 2004 demonstrating compliance with the applicable NOx limits in place at that time. This one-time only requirement has been completed and is not listed in the AOP.

Condition 20 requires that the project commence construction within 18 months of PSD-00-02 issuance. The refinery commenced construction of the project within 18 months. Condition 20 is considered obsolete and not included in the AOP.

Condition 21 is a PSD permit appeal provision. The 30-day timeline for appealing the PSD permit has expired. Condition 21 is considered obsolete and is not included in the AOP.

4.3.3 Regulatory Applicability

Refinery fuel gas combusted in the Alky Depropanizer Reboiler Heater and the S-Zorb Heater is required to meet the NSPS Subpart J standard for H_2S concentration in the fuel gas. Periodic tune-ups are required on the Alky Depropanizer Reboiler Heater and the S-Zorb Heater under the Boiler MACT. Miscellaneous process vents in the FCCU are subject to Refinery MACT provisions, and equipment components at the three process units in the Alkylation Processing Area are under leak detection and repair (LDAR) programs required by NSPS, Refinery MACT and OACs. Process waste drains in the Alkylation Processing Area are subject to control under NSPS Subpart QQQ.

The Alkylation Unit is divided into an acid-section and a non-acid section. Equipment components in the acid-section are not in HAP service and the Refinery MACT provisions for a LDAR program do not apply in the Alky acid-section. Similarly, equipment components in most areas of the Butamer, that are not handling perchloroethylene, are not in HAP service, and the Refinery MACT provisions for a LDAR program do not apply in those areas of the Butamer.

4.4 Tier III/LSR Hydrotreater Process Area

4.4.1 General Operation and Background

The Tier III/LSR Hydrotreater Process Area is comprised of one process unit, the Tier III/LSR Hydrotreater. The Tier III/LSR Hydrotreater Unit includes a charge heater and hydrotreating and distillation equipment. The unit is designed to remove sulfur from gasoline to meet federal Tier III gasoline standards. Feedstock to the unit is primarily light straight run naphtha which is blending stock for making gasoline products.

4.4.2 Construction History

NWCAA Order of Approval to Construct 1223 (OAC 1223) – Construct the Tier III/LSR Hydrotreater Unit

Original issuance October 23, 2015. No revisions.

OAC 1223 approved construction of the new Tier III/LSR Hydrotreater Unit including an 18.7 MMBtu/hour charge heater with low-NOx burner technology. The OAC includes NOx and CO limits on the heater with periodic source testing to demonstrate compliance. It also includes limits on the amount of H_2S in fuel gas combusted in the heater as BACT. The agency relied on subject federal requirements as BACT for fugitive leaks from equipment components and oily wastewater drains located at the unit. All the conditions of OAC 1223 have been listed in the AOP as applicable requirements. The NWCAA received notification of startup of the Tier III/LSR heater on January 10, 2019.

4.4.3 Regulatory Applicability

Refinery fuel gas combusted in the Tier III/LSR Heater is required to meet the NSPS Subpart Ja standard for H_2S concentration in the fuel gas. Periodic tune-ups are required on the heater under the Boiler MACT. Miscellaneous process vents at the Tier III/LSR heater are subject to Refinery MACT provisions and equipment components under leak detection and repair (LDAR) programs required by NSPS, Refinery MACT and OACs. Process waste drains at the Tier III/LSR heater area are subject to control under NSPS Subpart QQQ.

4.5 Reformer/Diesel Hydrotreater Process Area

4.5.1 General Operation and Background

The Reformer/Diesel Hydrotreater Process Area includes the #3 Reformer Unit and Diesel Hydrotreater Unit (DHT).

The #3 Reformer uses a catalytic reforming process to convert the "naphtha cut" from a low-octane material to a high-octane gasoline blending component and generates hydrogen as a byproduct that is used for hydrotreating (Figure 4-8). The #3 Reformer has four catalytic reforming reactors in series with a heater pass before each reactor. There is a fifth catalytic reforming reactor that is used as a swing reactor, whereby it is used when one of the four main reactors is going through a regeneration cycle. The swing reactor allows each of the four main reactors to be regenerated on an ongoing basis to ensure optimal conversion efficiency. The #3 Reformer is considered a “cyclic” catalytic reformer because of its ongoing catalyst regeneration capability.

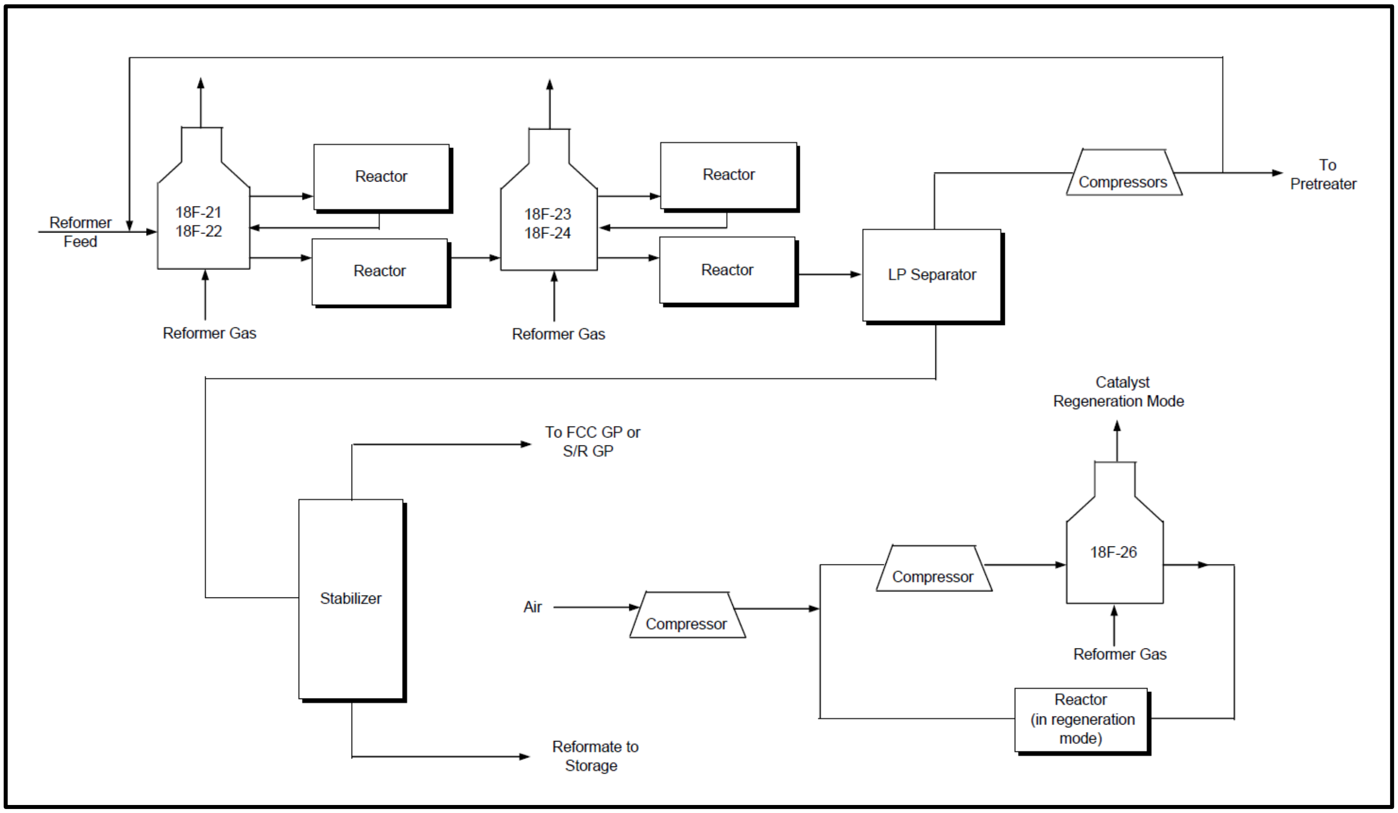

Figure 4-8 #3 Reformer Process Unit

The #3 Reformer includes a pretreater process that uses catalyst and heat to remove impurities, including sulfur, from the hydrocarbon stream before it enters catalytic reforming to protect the reforming catalyst from being poisoned (Figure 4-9). The pretreater is sometimes referred to as the “Hydrofiner”. The pretreater and catalytic reformer use and produce their own fuel gas.

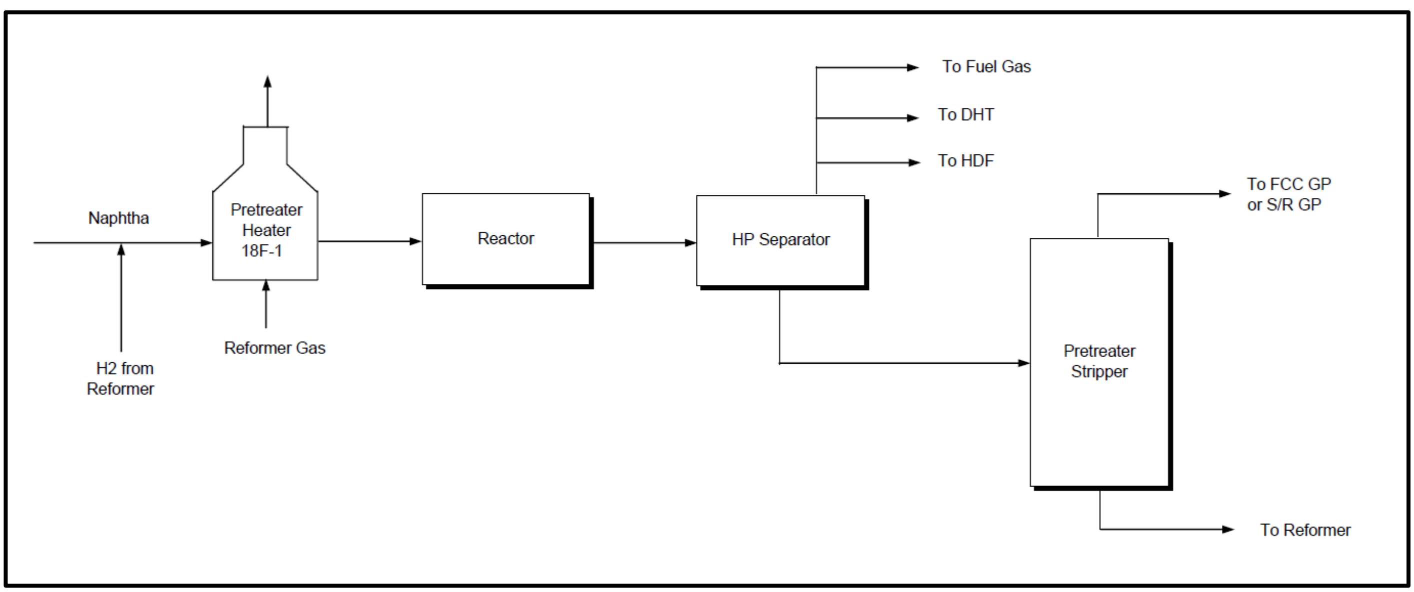

Figure 4-9 #3 Reformer Pretreater

The Diesel Hydrotreater Unit (DHT) reduces the amount of sulfur in both virgin and cracked diesel by hydrotreating with a catalyst and hydrogen, with hydrogen being supplied from the #3 Reformer (Figure 4-10). Sulfur compounds that are removed are sent to the Sulfur Recovery Unit (SRU) and low-sulfur diesel products are sent to storage.

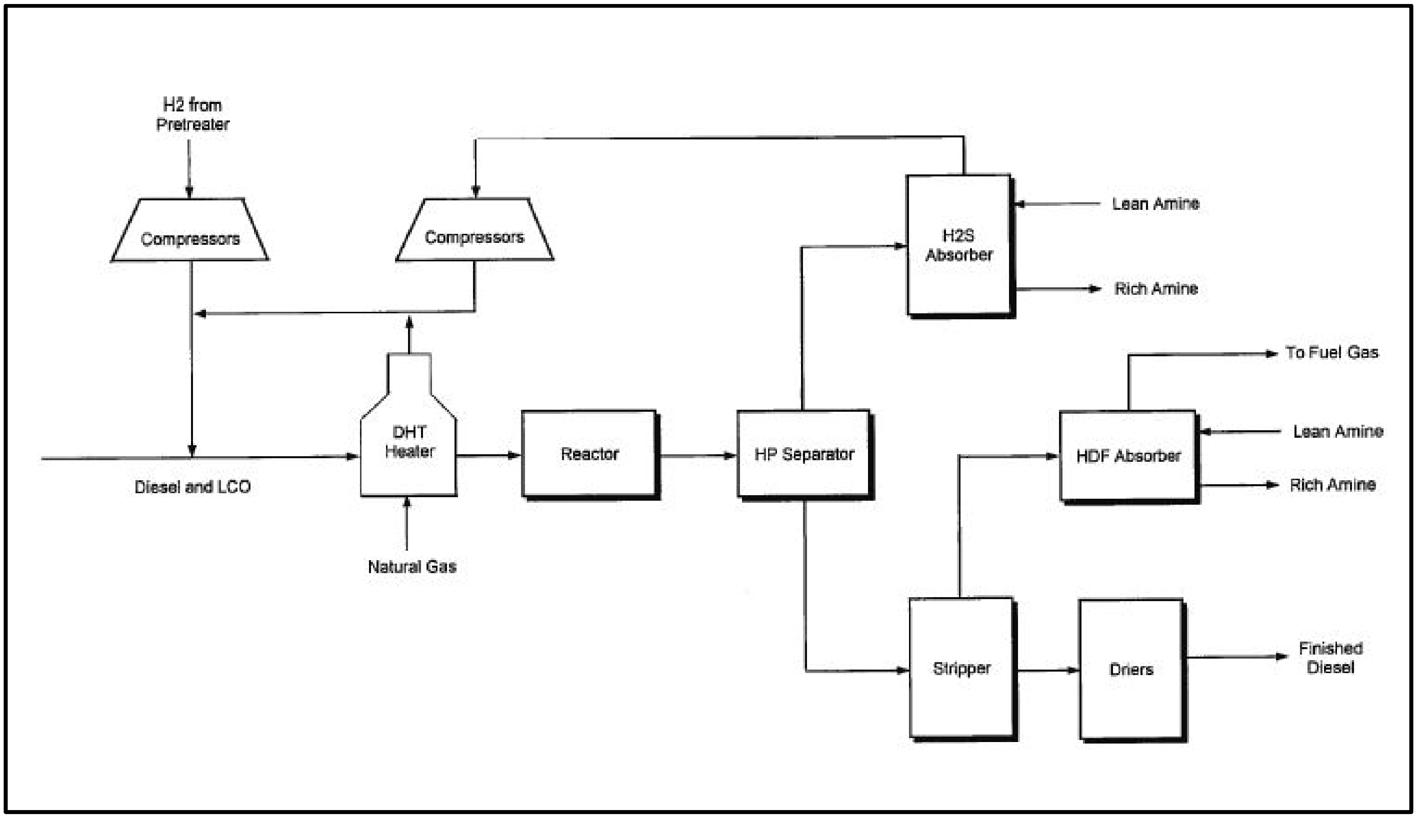

Figure 4-10 Diesel Hydrotreater Unit (DHT)

Emissions from the Reformer/Diesel Hydrotreater Process Area are from equipment component leaks (valves, pumps, compressors), products of combustion from process heaters, emissions generated from reformer regeneration exhaust, oily wastewater routed to drains and from miscellaneous process vents.

4.5.2 Construction History

The #3 Reformer was built in 1972 replacing similar catalytic reforming units that were constructed during original refinery construction. A chloride scrubber was added to the #3 Reformer in 2005 allowing the catalytic regeneration vent to comply with 40 CFR 63 Subpart UUU. The Diesel Hydrotreater Unit (DHT) was built in 1992 and modified in 1995. In 2001/2002, the DHT Heater (33F-1) increased its firing capacity and was reconfigured to burn refinery fuel gas, in addition to natural gas. In 2005 the DHT was modified with additional catalytic reactors to allow continuous production of Ultralow Sulfur Diesel (ULSD). The following is a summary of the construction projects at the Reformer/DHT Process Area that received formal approval from the NWCAA.

NWCAA Order of Approval to Construct dated January 14, 1972 - #3 Reformer/Octane Improvement Project

Original issuance January 14, 1972. No revisions. Narrative with no requirements.

This approval order authorized construction of the #3 Reformer. However, the approval letter has no requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 343 – Construct a new Diesel Hydrotreater (DHT) Unit

Original issuance October 3, 1991. No revisions. Superseded by OAC 780.

OAC 343 approved construction of the Diesel Hydrotreater (DHT) Unit that included the DHT Heater (33F-1) with a heat input capacity of 30.2 MMBtu per hour. The heater was approved for the combustion of purchased natural gas only.

OAC 343 was superseded upon issuance of OAC 780 on July 26, 2001. OAC 343 included Condition 3 specifically subjected the heater to NSPS 40 CFR 60.590-593 Subpart GGG. When OAC 343 was superseded, this LDAR condition was not included in OAC 780 because equipment leaks at the DHT Unit were subject to 40 CFR 60 Subpart GGG directly.

NWCAA Order of Approval to Construct 552 – Modification to the Diesel Hydrotreater (DHT) Heater (33F-1) to increase firing rate

Original issuance June 5, 1995. No revisions. Superseded by OAC 780.

OAC 552 approved an increase to the firing rate of the DHT Heater from 30.2 MMBtu per hour to 48 MMBtu per hour. This OAC did not approve the combustion of any additional fuels beyond the already approved combustion of purchased natural gas. OAC 552 was superseded upon issuance of OAC 780 on July 26, 2001.

NWCAA Order of Approval to Construct 733f - Ferndale Upgrade/Clean Fuels Project

Original issuance April 6, 2001. Revised August 13, 2002, June 8, 205, July 29, 2005, August 2, 2012, September 30, 2016, and December 10, 2019.

OAC 733 initially did not address any equipment at the DHT Unit or #3 Reformer Unit. During revisions OAC 733c and OAC 733e the approval order was revised to include Consent Decree obligations that were federally enforceable requirements. These requirements included making the DHT Heater (33F-1) and all the process heaters at the #3 Reformer subject to 40 CFR 60 Subpart J limiting the amount of H_2S in the fuel gas combusted in those heaters. Another Consent Decree based requirement restricted the DHT Heater and #3 Reformer heaters from combusting fuel with a sulfur content greater than 0.05% by weight. These Consent Decree based requirements in OAC 733e are listed in the AOP. Revision 733f cleaned up the OAC for incorporation into the AOP renewal and provided for SS&M flexibility at SRU #1.

NWCAA Order of Approval to Construct 780b – Modification to Diesel Hydrotreater (DHT) Heater (33F-1) to facilitate the combustion of refinery fuel gas.

Original issuance July 26, 2001, revised June 9, 2016, second revision on December 22, 2021.

Order of Approval to Construct 780 superseded in whole, previously issued OAC 343 and OAC 552 for construction of the DHT Unit including the DHT Heater. OAC 780 approved the combustion of refinery fuel gas in addition to purchased natural gas in the DHT Heater. The project did not increase the firing capacity of the heater beyond its rated capacity of 48 MMBtu/hour approved under OAC 552. The DHT Heater became subject to the SO_2 limit of 40 CFR 60 Subpart J because it is considered a new refinery fuel gas combustion device under the rule. The refinery complies with Subpart J by continuously monitoring the H_2S content of the refinery fuel gas to ensure compliance with the 3-hour, 162 ppmv specified by Subpart J as a surrogate to the SO_2 limit.

On January 15, 2002, the NWCAA received a written notice that the DHT Heater began combusting refinery fuel gas upon startup after the modification.

OAC 780 was revised to OAC 780a for cleanup prior to incorporation onto the AOP. OAC 780a was revised to 780b with replacement of the DHT burners. This revision included requirements to perform an initial source test on the new burners within 180 days of firing. Thereafter, annual testing of NO_X using a portable emissions monitor and source testing every 60 months in accordance with EPA Methods 19 and 7E. Condition 5 includes a visible emissions limit of 5% opacity for the DHT heater using EPA Method 9. This condition does not include ongoing MR&R to determine compliance. The NWCAA added a gap-filled requirement to periodically check for compliance using a refinery-wide visual emissions monitoring program listed in Section 6 of the AOP.

NWCAA Order of Approval to Construct 864a – Install a Dry Chloride Scrubber on the #3 Reformer Catalyst Regeneration Vent

Original issuance October 27, 2004. Revised June 9, 2016.

A dry chloride scrubber was installed on the #3 Reformer Catalytic regeneration vent to comply with the Refinery MACT 2 40 CFR 63 Subpart UUU. The dry chloride scrubber removes hydrogen chloride (HCl) from the vent stream while the catalyst is being regenerated. In general, catalyst regeneration occurs every six months. Exhaust from the dry chloride scrubber is routed to the CO Boiler where organic air pollutants are combusted. OAC 864a revision was a cleanup prior to incorporation onto the AOP.

OAC 864a is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 886 – Addition of two Reactors to the DHT

Original issuance March 3, 2005. No revisions.

OAC 886 approved installation of two new reactors on the Diesel Hydrotreater (DHT) to improve catalyst run life and aid in production of ultra-low sulfur diesel fuel. The new reactors replaced the previous single reactor, increasing the total reactor volume from 2,700 to 13,000 cubic feet. The project was not intended to debottleneck the DHT Unit with the nominal diesel production of the unit remaining at 32,000 barrels per day.

All the conditions of OAC 886 are included in the AOP with the exception of Condition 3. Condition 3 requires a notification of DHT startup following completion of the project. The NWCAA received this startup notice on February 10, 2006. This one-time only requirement has been completed and Condition 3 is not included in the AOP.

NWCAA Order of Approval to Construct 1245 – Modify process equipment at the DHT

Original issuance April 1, 2019.

Addition of valves and connectors at the DHT unit. The OAC contained one condition requiring notification of startup and as this has been completed, the OAC is not included in the AOP.

4.5.3 Regulatory Applicability

Equipment components at the Reformer/DHT process area are subject to leak detection and repair (LDAR) requirements under federal NSPS (VOC) and NESHAP (HAP) regulations. LDAR requirements under NWCAA 580.8 do not apply because feedstocks to the #3 Reformer and DHT are not butane or lighter. There are several compressors in the DHT process area that are considered in hydrogen service and therefore exempt from LDAR.

Refinery fuel gas combusted in the DHT Heater is subject to the NSPS 40 CFR 60 Subpart J and the H_2S content of the fuel gas is continuous monitored for compliance.

There are various oily wastewater drains in the Reformer/DHT Process Area that are subject to control requirements under the 40 CFR 61 Subpart FF (BWON) and 40 CFR 63 Subpart CC (Refinery MACT 1).

There are a number of miscellaneous process vents in the Reformer/DHT Process Area subject to control requirements under 40 CFR 63 Subpart CC. Emissions from these vents are controlled by routing to the flare gas recovery system and flare.

Emissions from catalytic regeneration at the #3 Reformer is subject to HAP control under 40 CFR 63 Subpart UUU. A dry chloride scrubber is used to control HCl, the regulated metal HAP. Exhaust from the scrubber is routed to the CO Boiler. The dry chloride scrubber is considered a fixed-bed gas-solid adsorption system under Subpart UUU and compliance is demonstrated by monitoring the daily average temperature of the intake or exhaust to the scrubber, with the temperature determined by a performance test for HCl that was completed in April 2005, and HCl samples taken with Draeger tubes each shift during catalyst rejuvenation. Organic HAPs are control by the flare gas recovery system and flare during initial isolation and depressurization of the catalyst bed for compliance with Subpart UUU.

The catalyst regeneration vent, regulated by Subpart UUU, either vents to the flare system or to the dry chloride scrubber and CO Boiler depending on the portion of the regeneration cycle that is occurring. The catalyst regeneration is a cyclic event that occurs about once every 60 hours in the following steps: 1) isolation and depressuring (vent to flare), 2) coke burn-off (vent to dry chloride scrubber), 3) maintenance (no venting), 4) first catalyst rejuvenation (vent to dry chloride scrubber), 5) sulfate removal (optional), 6) second catalyst rejuvenation (vent to dry chloride scrubber), 7) cool down (no venting), and 8) reduction (no venting).

Under 40 CFR 63 Subpart UUU, the refinery is required to develop and implement an operation, maintenance, and monitoring plan (OMMP) to ensure ongoing compliance with the emission standards of Subpart UUU. The OMMP must be submitted and approved by the agency prior to implementation. On September 9, 2005, the NWCAA received the OMMP for the #3 Reformer dated "August 2005". A file review during the 2017 AOP renewal process did not find a record indicating that the August 2006 plan was previously approved by the agency. Therefore, NWCAA implicitly approved the OMMP as part of the 2017 AOP renewal process because the AOP term requiring the OMMP refers to the August 2006 plan for determining ongoing compliance with Subpart UUU.

4.6 Sulfur Plant/Treaters Process Area

4.6.1 General Operation and Background

The Sulfur Plant/Treaters Process Area includes two sulfur recovery units (SRU #1 and SRU #2), each composed of a single train, three-stage Claus sulfur recovery unit (SRU), a SCOT tail gas treating unit (TGU) and a TGU incinerator (Figure 4-11). The process area also includes various amine treating devices including a MEROX treating unit that was constructed in 2000. These process units are involved primarily in removing sulfur and, to a lesser extent, other contaminants from process streams. Individual amine absorber units at different locations within the refinery circulate amine to strip hydrogen sulfide (H_2S) from the hydrocarbon process streams. The "acid gas" generated during amine stripping and "sour gas" from the sour water stripper, are fed to the Claus units where H_2S is converted to elemental sulfur and ammonia (NH_3) destroyed into products of combustion. The residual H_2S that is not converted into elemental sulfur in the Claus units is routed to the SCOT Tail Gas units for additional recovery. Any H_2S remaining in the TGU exhaust is sent to incinerators where it is oxidized to SO_2 prior to discharge.

Emissions associated with the Sulfur Plant/Treaters process area includes products of combustion emitted at the incinerator stacks and fugitive emissions from equipment leaks (valves, pumps, elemental sulfur tank, and miscellaneous process vents and drains).

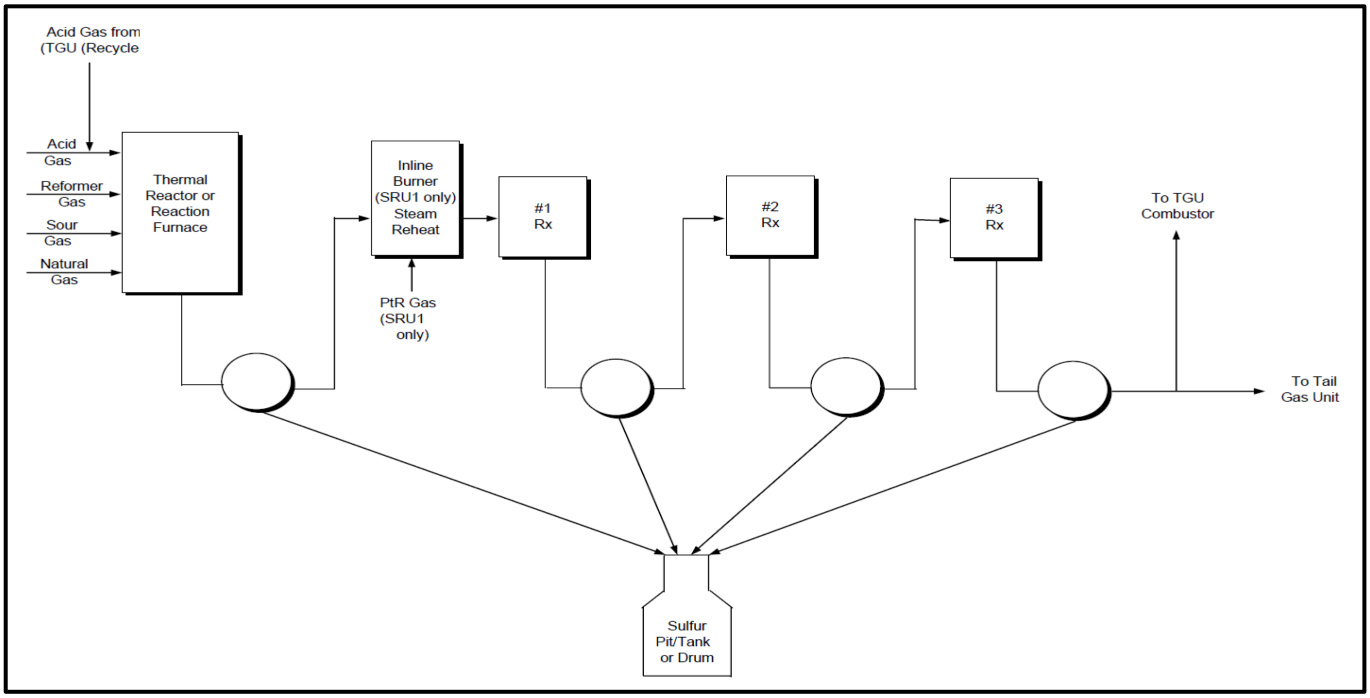

Figure 4-11 Sulfur Recovery Process

4.6.2 Construction and Permitting History

Sulfur Recovery Unit (SRU #1) was installed in 1978 under OAC 185, issued on July 15, 1976. On June 1, 1982, the agency approved an increase in the elemental sulfur recovery rate of SRU #1 to 19.5 long tons per day (LTD) (undocumented). In 1991, Tail Gas Unit # 1 (TGU #1) was added to SRU #1 as approved under OAC 294 issued September 5, 1990. In 2001, OAC 294 was superseded by OAC 733.

In 1999, an oxygen enrichment system was added to SRU #1 increasing its capacity to 55 LTD. The oxygen enrichment project was approved under OAC 681. OAC 681 was also superseded by OAC 733 in 2001.

In 2006, a second sulfur recovery unit (SRU #2) was constructed to increase the sulfur removal capacity of the Sulfur Plant and to provide redundant SRU operation. The SRU #2 was approved under OAC 908.

The following summarizes NSR approvals affecting equipment in the Sulfur Plant/Treaters Process Area.

NWCAA Order of Approval to Construct 185 – Construction of Sulfur Recovery Unit #1 (SRU #1)

Original issuance July 15, 1976: No revisions.

OAC 185 is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 727a – Construction of the Merox Extraction Unit

Original issuance May 31, 2000. Revised June 9, 2016.

OAC 727 approved construction of the Merox Extraction Unit (Merox Unit) that employs a catalytic mercaptan oxidation system to remove sulfur from olefins that are then routed to the Alkylation Unit. OAC 727 was revised to OAC 727a for AOP cleanup prior to incorporation onto the AOP. OAC 727a includes only one condition and this condition is included in the AOP.

NWCAA Order of Approval to Construct 733f - Ferndale Upgrade/Clean Fuels Project

Original issuance April 6, 2001. Revised August 13, 2002; June 8, 205, July 29, 2005, August 2, 2012, September 30, 2016, and December 10, 2019.

The Ferndale Upgrade/Clean Fuels project, permitted in 2001 under OAC 733 and PSD-00-02 (and subsequent revisions), approved construction of the Cat Gas Desulfurization Unit (CGD/S-Zorb Unit) located in the Alkylation Process Area. The CGD/S-Zorb Unit was designed to remove sulfur from gasoline to allow the refinery to produces gasoline that met upcoming federal standards at that time. This project increased sulfur loading at the SRU #1. The SRU #1 was equipped with 100% oxygen injection technology to handle the increased load. OAC 733 included stack SO_2 concentration limits as BACT for SRU #1 and limited supplemental fuel used in the SRU #1 incinerator to purchased natural gas.

During OAC 733c and OAC 733e the approval order was revised to incorporate Consent Decree (CD) obligations as federally enforceable requirements. There are two CD requirements in OAC 733e: conduct a root cause analysis for tail gas flaring events and control emissions from the elemental sulfur pit, or monitor sulfur pit emissions with a 40 CFR 60 Subpart J quality CEMS.

All the requirements of OAC 733e for equipment located at the Sulfur Plant/Treaters Process Area are listed in the AOP. Condition 3 is a 10% opacity limit on the SRU #1 incinerator stack. The MR&R for this requirement has been gap-filled in the AOP with a common visual emission monitoring program for the refinery. Revision 733f cleaned up the OAC for incorporation into the AOP renewal and provided for SS&M flexibility at SRU #1.

NWCAA Order of Approval to Construct 908c – Crude/FCCU/SRU Upgrade Project

Original issuance November 17, 2005. Revised November 6, 2006, June 9, 2016, and August 20, 2019.

The project approved under OAC 908 was for SO_2 and TAPs. All other reviewable air pollutants were addressed under PSD-05-01 issued by WDOE. The project included modifications to the Crude Unit, Fluidized Catalytic Cracking Unit (FCCU) gas plant, and refinery amine system. The project was designed to increase crude charge to the Crude Unit and FCC feed charge rates at the FCCU as well as add equipment to remove the increased sulfur resulting from these higher charge rates. The project did not include any physical modifications to the process units that would increase air emissions other than adding a limited number of equipment components subject to leak detection and repair. The new equipment components were incorporated into the existing leak detection and repair program, therefore, no LDAR requirements were included in the OAC.

The project included construction of a new Claus sulfur recovery unit and associated SCOT Tail Gas Unit and incinerator. This group of equipment is commonly referred to as SRU #2. The SRU #2 has a design recovery capacity of 60 long tons per day of elemental sulfur when operated with oxygen injection. The OAC has undergone two administrative revisions.

Revision 908c added an option to route sulfur storage tank emissions to the SRU #1 incinerator, add SS&M flexibility, and allow more control options for the elemental sulfur sweep gas.

All conditions of OAC 908c have been incorporated into the AOP. Condition 2 is a 10% opacity limit on the SRU #2 incinerator stack. The MR&R for this requirement has been gap-filled in the AOP with a common visual emission monitoring program for the refinery.

WDOE Prevention of Significant Deterioration (PSD) Permit PSD-00-02 Amendment 8 - Ferndale Upgrade/Clean Fuels Project

Originally issued April 4, 2001. Revised eight times to current Amendment 8 issued September 9, 2015.

Similar to OAC 733, PSD-00-02 approved construction of the CGD Unit located in the Alkylation Process Area in 2001. The current version, PSD-00-02 Amendment 8 has numerous conditions that are considered ongoing requirements. All these requirements are listed in the AOP except as noted below.

Condition 15 limits the firing rate of the SRU #1 to 23 MMBtu/hour. Combustion occurs at the SRU #1 from H_2S oxidation in the Claus sulfur recovery unit and in the SRU #1 incinerator. However, the intent of Condition 15 is to limit supplemental fuel firing in the SRU #1 Incinerator to 23 MMBtu/hour. The AOP term is written to limit the total firing rate in the SRU #1 Incinerator. This includes both natural gas supplied as supplemental fuels and acid gas from the SRU/TGU. The PSD permit limit does not asterisk the firing rate of the incinerator with the footnote "Applies when auxiliary firing fuel gas", therefore, the 23 MMBtu/hour limit is assumed to be total of all heat inputs.

Condition 13 requires an initial NO_X source test on SRU #1. Initial testing was conducted in June 2003 demonstrating compliance with the applicable NO_X limits in place at that time. This one-time only requirement has been completed and is not listed in the AOP.

Condition 20 requires that the project commence construction within 18 months of PSD-00-02 issuance. The refinery commenced construction of the project within 18 months. Condition 20 is considered obsolete and not included in the AOP.

Condition 21 is a PSD permit appeal provision. The 30-day timeline for appealing the PSD permit has expired. Condition 21 is considered obsolete and is not included in the AOP.

WDOE Prevention of Significant Deterioration Permit PSD-05-01 – Crude/FCCU/SRU Upgrade Project

Original issuance November 14, 2005. No amendments.

All conditions of PSD-05-01 have been incorporated into the AOP with the following revisions.

Condition 1 incorrectly refers to Condition 4 as the test method for NO_X. Condition 4 is the test method for CO. The AOP term cites Condition 3, the correct test method for NO_X.

Condition 2 incorrectly refers to Condition 5 as the test method for CO. Condition 5 does not include a test method. The AOP term cites Condition 4, that has the test method for CO.

Condition 10 requires that the project commence construction within 18 months of PSD-05-01 issuance. The refinery commenced construction of the project within 18 months. Condition 10 is considered obsolete and not included in the AOP.

Condition 11 is a provision concerning the effective date of PSD-05-01 being no earlier than the date that U.S. EPA notifies the WDOE that they have satisfied the obligation for consultation under the Endangered Species Act. Condition 11 is considered obsolete and not included in the AOP.

Condition 12 is a condition on the effective date of PSD-05-01 allowing it to be suspended if there are public comments within 30 days of issuance. There is no record of public comments on PSD-05-01. Condition 12 is considered obsolete and not included in the AOP.

4.6.3 Regulatory Applicability

Both SRU #1 and SRU #2 are subject to a 250 ppmvd, 12-hour average SO_2 standard under NSPS 40 CFR 60 Subpart J. In addition, SRU #2 has SO_2 limits established as BACT under OAC 733f. CEMS are used to determine continuous compliance with these SO_2 standards. NOx and CO limits for SRU #1 and SRU #2 are established as BACT under PSD-00-01 and PSD-05-01, respectively. Compliance with the NO_X and CO limits are determined through periodic source testing. Lastly, limits on visual opacity from SRU #1 and SRU #2 are established as BACT under OAC 733f and OAC 908b, respectively.

SRU #1 and SRU #2 are subject to HAP control requirements under 40 CFR 63 Subpart UUU. In general, Subpart UUU relies on the SO_2 standard in NSPS Subpart J for HAP control. §63.1569 regulates bypass lines; however, Phillips 66 does not have bypass lines that meet the definition in the rule; the lines are not piped to atmosphere. Therefore, this federal requirement does not apply to the sulfur recovery units and is not included in the AOP. However, SRU #2 contains a permit term referencing OAC 908c Condition 6 requiring continuous monitoring of the lines that bypass TGU #2 and reporting of events where flow is detected in a TGU #2 bypass line. This term was retained as it is applicable through OAC 908c. Subpart UUU requires that the refinery develop and implement an operation, maintenance, and monitoring plan (OMMP) to ensure ongoing compliance with the SO_2 standard. The OMMP must be submitted and approved by the agency prior to implementation. On June 30, 2016, the NWCAA received OMMPs dated "June 2016" for both SRUs. The NWCAA implicitly approved these plans as part of the 2017 AOP renewal process because the AOP terms requiring the OMMPs refer to the June 2016 plans to determining ongoing compliance with Subpart UUU.

Equipment components at the Sulfur Recovery Plant and Merox Unit are subject to leak detection and repair (LDAR) programs. Specifically, fugitive VOC leaks at the Merox Unit are subject to NSPS requirements under 40 CFR 60 Subpart GGG and a more stringent version of the Subpart GGG requirements as BACT under OAC 727a. Fugitive HAP leaks at both the Sulfur Recovery Plant and Merox Unit are subject to MACT requirements under 40 CFR 63 Subpart CC.

4.7 Utilities Process Area

4.7.1 General Operation and Background

The Utilities Process Area includes four utility boilers that generate steam used to provide heat for process units in the refinery. The utilities area also includes two cooling towers, serving the boilers. Some steam for Phillips 66 is provided by the adjacent PSE Ferndale cogeneration power plant. The cogeneration plant is not owned or operated by Phillips 66 and is not part of this air operating permit (AOP).

The two, non-contact, circulating, cooling towers service two segregated cooling water systems at the refinery. One cooling tower handles cooling water from the Alkylation process area. The other cooling tower handles cooling water from the rest of the refinery. As presented in Figure 4-12, the refinery has four gas-fired utility boilers. The #2 Boiler (22F-1A) has a heat input capacity of 91 MMBtu/hour and the #3 Boiler (22F-1B) has a heat input capacity of 108 MMBtu/hour.

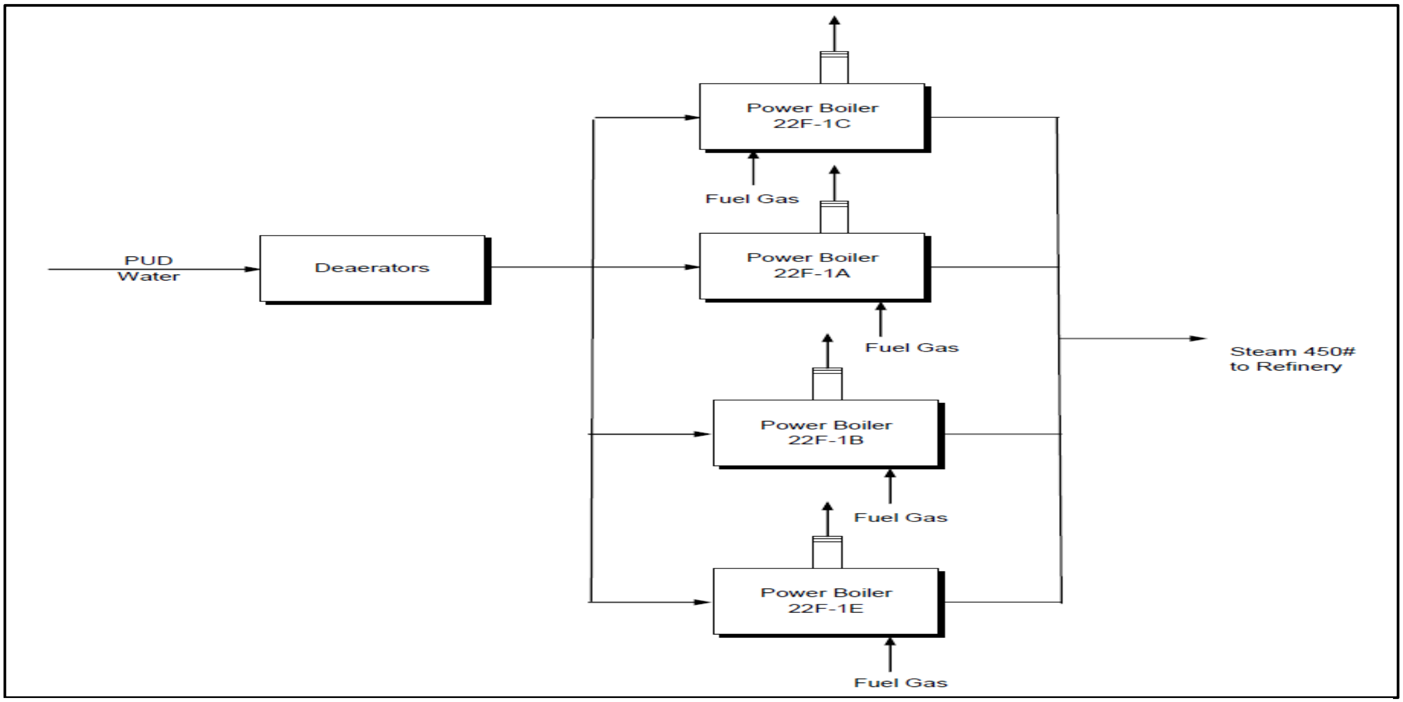

Figure 4-12 Utilities Process Area

4.7.2 Construction and Permitting History

The #1 Boiler, with a heat input capacity of 162 MMBtu/hour boiler, was constructed in 1996 and approved under OAC 578. The #1 Boiler replaced a temporary 99 MMBtu/hour boiler installed in January 1996 under OAC 581. The temporary boiler was decommissioned when the #1 Boiler came online. Another temporary boiler rated at 88 MMBtu/hour was constructed in 2003 under OAC 849. This temporary boiler was replaced in 2006 by the #4 Boiler. The #4 Boiler has a heat input capacity of 164 MMBtu/hour and was approved under OAC 877. The 88 MMBtu/hour temporary boiler was decommissioned when the #4 Boiler came online. The boilers are configured to combust refinery fuel gas; the #4 Boiler primarily combusts natural gas since operation began in 2006.

NWCAA Order of Approval to Construct 578b – Construction of the #1 Boiler

Original issuance April 9, 1996. Revised August 13, 2008, and June 9, 2016.

The project approved under OAC 578 involved construction of the #1 Boiler with a heat input capacity of 162 MMBtu per hour. The OAC was revised August 13, 2008, to incorporate a lower NO_X limit (from 0.05 lb/MMBtu to 0.04 lb/MMBtu) as required by the refinery's Consent Decree and to remove the option to combust fuel oil that was never utilized. The #1 Boiler is equipped with low-NO_X burners and flue gas recirculation to control NO_X emissions. The #1 Boiler is subject to the SO_2 limit in 40 CFR 60 Subpart J as a refinery fuel gas combustion device and the NO_X limit of 40 CFR 60 Subpart Db as a new industrial steam generating unit. The OAC 578b revision cleaned up the permit for inclusion in the second AOP renewal.

All conditions of OAC 578b are included in the AOP. Condition 3 includes a visual emission limit of 5% opacity using EPA Method 9 but does not include an ongoing compliance demonstration method. The AOP gap-fills MR&R for the opacity limit with a requirement to use a common refinery-wide visual emission monitoring program.

NWCAA Order of Approval to Construct 877b – Construction of the #4 Boiler

Original issuance August 12, 2004. Revised September 15, 2008, and June 9, 2016.

OAC 877 approved construction of the #4 Boiler with a heat input capacity of 164 MMBtu per hour. NO_X emissions are controlled by ultra-low NO_X burners combined with flue gas recirculation. The #4 Boiler is subject to the SO_2 limit in 40 CFR 60 Subpart J as a refinery fuel gas combustion device and the NO_X limit of 40 CFR 60 Subpart Db as a new industrial steam generating unit.

On September 15, 2008, the OAC was revised removing the requirement for biennial source testing of particulate because testing had demonstrated minimal particulate emission rates. The June 9, 2016, revision (OAC 877b) was done for cleanup prior to incorporation onto the AOP.

All the conditions of OAC 877b are included in the AOP. Condition 2 includes a visual emission limit of 5% opacity using EPA Method 9 but does not include an ongoing compliance demonstration method. The AOP gap-fills MR&R for the opacity limit with a requirement to use a common refinery-wide visual emission monitoring program.

NWCAA Order of Approval to Construct 733f - Ferndale Upgrade/Clean Fuels Project

Original issuance April 6, 2001. Revised August 13, 2002, June 8, 2005, July 29, 2005, August 2, 2012, September 30, 2016, and December 10, 2019.

OAC 733 initially did not address any equipment at the Utilities Process Area. During revisions OAC 733c and OAC 733e the approval order was revised to include Consent Decree obligations so that they were federally enforceable requirements. These requirements included subjecting all the utility boilers to 40 CFR 60 Subpart J limiting the amount of H_2S in the fuel gas combusted in those heaters. The other Consent Decree based requirement restricts the four utility boilers from combusting fuel with a sulfur content greater than 0.05% by weight. The Consent Decree based requirements in OAC 733f are listed in the AOP.

4.7.3 Regulatory Applicability

The #1 Boiler and #4 Boiler are subject to the NO_X emission limit under 40 CFR 60 Subpart Db. The #1 Boiler and #4 Boiler are also subject to more stringent NO_X limits under OAC 578b and OAC 877b, respectively. OAC 877b includes a CO limit established as BACT for the #4 Boiler. These boilers are outfitted with CEMS to continuously monitor compliance with the gaseous pollutants' emission limits.

Because of their construction date, both the #1 and #4 Boiler are subject to the NSPS limit for sulfur dioxide set forth in 40 CFR 60 Subpart J when combusting refinery fuel gas. The refinery meets the Subpart J compliance obligation by continuously monitoring the H_2S content of the fuel gas combusted in the boiler to ensure that it does not exceed 162 ppmvd as a surrogate for the SO_2 standard. OAC 877b imposes a more stringent BACT standard for the H_2S content of the fuel gas combusted in the #4 Boiler at 50 ppmvd. The older #2 and #3 Boilers must meet the Subpart J sulfur standard as a requirement of OAC 733f. This condition was included in the OAC 733e revision to memorialize this obligation from the Consent Decree.

The two cooling towers are subject to the §63.654 - Heat Exchange Systems provisions of 40 CFR 63 Subpart CC. The rule requires that the cooling towers be checked periodically for hydrocarbon leaks that can occur in the cooling water system. When leaks are found, the refinery is required to take corrective action in a timely manner to fix the leaks. Because the hydrocarbon leaks emanate from leaking heat exchangers within various process units within the refinery, the required work practice is to identify leaking heat exchangers and initiate repairs.

The cooling towers are also subject to 40 CFR 63 Subpart Q - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers. This standard prohibits the use of chromium-based treatment chemicals in cooling water systems. Phillips 66 provided the required initial notification by letter received August 1, 1995, and the required notification of compliance status by letter received May 1, 1996, stating that they do not use chromium-based treatment chemicals in the cooling water. These one-time notification requirements have been completed and there are no ongoing requirements for monitoring, recordkeeping, or reporting under Subpart Q. Therefore, Subpart Q is not included in the AOP.

4.8 Flare System

4.8.1 General Operation and Background

The refinery is equipped with a steam-assisted, elevated flare to combust excess hydrocarbon gases during abnormal operations at the refinery such as unplanned process unit shutdowns. The steam is injected into the flared gases at the flare tip to enhance destruction efficiency and to mitigate visible emissions. Excess gases at the refinery are routed to a common flare header. The flare header is kept at or below 60 inches of water column (60″ H_2O) pressure by a water seal that is integrated with the elevated flare. When the flare header exceeds 60″ H_2O, the water seal is broken, and the header relieves pressure to the elevated flare through the water seal. Flaring is minimized by the Flare Gas Recovery unit (FGR) that utilizes compressors to route gases from the flare header to the refinery fuel gas system. An amine scrubbing system removes H_2S from the gases prior to the gas entering the fuel gas system.

4.8.2 Construction and Permitting History

During original refinery construction in 1953, the facility was equipped with a ground flare to combust excess hydrocarbon gases. In 1972, the refinery installed a John Zink Thermal Oxidizing Flare (ZTOF) approved under a letter issued by the NWCAA on December 17, 1971. In 2010, the refinery installed a Flare Gas Recovery Unit approved by NWCAA under OAC 1029. The flare gas recovery unit was installed in response to Consent Decree obligations. On April 10, 2014, NWCAA Compliance Order No. 11 went into effect implementing Consent Decree obligations at the ZTOF and Emergency Ground Flare.

In 2015, the ZTOF and ground flare were decommissioned and replaced during the Flare Infrastructure Upgrade Project that included a new, steam-assisted, elevated flare approved under OAC 1174. Because the ZTOF has been decommissioned, the NWCAA approval letter issued December 17, 1971, is no longer applicable and is not listed in the AOP. Similarly, NWCAA Compliance Order No. 11 is not listed in the AOP because the ZTOF and ground flare are no longer in use at the refinery.

NWCAA Order of Approval to Construct 1029 – New Flare Gas Recovery Unit

Original issuance October 16, 2008. No revisions.

OAC 1029 approved the Flare Gas Recovery Unit comprised of three sliding vane compressors, air-cooled discharge and intercooler exchangers, and an amine contactor. Under the Consent Decree, flare gas recovery was required at Phillips 66 by the end of 2011.

All conditions of OAC 1029 have been included in the AOP with the following exceptions:

Condition 2 requires monitoring of a control valve that was used to route gases from the flare header to the flare gas recovery unit prior to the Flare Infrastructure Upgrade project. This valve was removed from service during the Flare Infrastructure Upgrade project approved in 2014 under OAC 1174. At present, the gas recovery system cannot be isolated from the flare header with a valve. Condition 2 is no longer applicable and is not listed in the AOP.

Condition 4 second sentence states “Other new fugitive leak components shall be included in the leak detection and repair programs applicable to the process areas in which they are located”. This sentence is not practically enforceable and overlaps the requirement for LDAR in process units outside the Flare Gas Recovery Unit. Therefore, this sentence has not been included in the AOP.

Condition 6 requires that the NWCAA be notified when the Flare Gas Recovery Unit construction has been completed. On May 24, 2010, the NWCAA received a letter from Phillips 66 stating that the new Flare Gas Recovery Unit came online May 14, 2010. The one-time only requirement of OAC 1029 Condition 6 has been completed and is not listed in the AOP.

NWCAA Order of Approval to Construct 1174 – Flare Infrastructure Upgrade Project

Original issuance March 7, 2014. No revisions.

OAC 1174 approved the Flare Infrastructure Upgrade Project comprised of constructing a new 199' foot high, steam-assisted, elevated flare, new blowdown drum to eliminate liquids from entering the flare and a new water seal located at the base of the flare. The project included decommissioning the ZTOF and ground flare.

All conditions of OAC 1174 have been included in the AOP with the following exceptions:

Condition 6 requires that the NWCAA be provided a copy of the design specifications for the new elevated flare as required under 40 CFR 60 Subpart A, prior to startup of the flare. On June 30, 2015, the NWCAA received the required information including the maximum design velocity at the flare tip. The one-time only requirement of OAC 1174 Condition 6 has been completed and is not listed in the AOP.

Condition 8 requires that the NWCAA be provided a copy of the flare management plan for the new elevated flare as required under 40 CFR 60 Subpart Ja, prior to startup of the flare. On June 30, 2015, the NWCAA received the flare management plan. The one-time only requirement of OAC 1174 Condition 8 has been completed and is not listed in the AOP.

Conditions 10 and 11 require that the NWCAA be notified of the decommissioning date of the ZTOF and ground flare, the initial firing date of the pilot on the new elevated flare, and the commissioning date of the new elevated flare. On October 14, 2015, the NWCAA received a letter stating that the ZTOF and ground flare were decommissioned prior to startup of the new elevated flare, and that initial firing of the pilot on the new flare occurred on October 5, 2015, and initial flaring of flare gases occurred on October 6, 2015. The one-time only requirements of OAC 1174 Conditions 10 and 11 have been completed and they are not listed in the AOP.

4.8.3 Regulatory Applicability

The flare system is used to capture and control waste gas generated by miscellaneous process vents regulated under 40 CFR 63 Subpart CC (Refinery MACT 1) and to control fugitive equipment leaks regulated under 40 CFR 60 Subparts GGG and GGGa and their respective control strategies under Subparts VV and VVa. Waste gas from miscellaneous process vents and fugitive equipment leaks are routed to a flare gas header and the FGR recovers, to the extent it is capable, the waste gas for use as refinery fuel gas. When the FGR reaches recovery capacity the excess waste gas is sent to the elevated flare where it is destroyed through combustion. To ensure good destruction efficiency the flare must meet applicable standards.

Prior to January 30, 2019, the applicable standard came from 40 CFR 60 Subpart A §60.18. However, on and after January 30, 2019, a new, more robust standard for flares is required under 40 CFR 63 Subpart CC §63.670. The new standard includes periodic or continuously monitoring of gas flare to ensure that it: 1) does not lead to excessive visual emissions, 2) The flare tip velocity does not exceed its rated capacity, and 3) the heat content of all gases, including dilution from steam, is high enough in the combustion zone to ensure good VOC and HAP destruction efficiency.

There are minor sources of non-HAP streams routed to the flare header. However, given the wide array of HAP sources that are routed to the flare header, it is highly unlikely that the facility could claim that a flaring event did not contain any HAP regulated material. In addition, the refinery has a robust flare gas recovery system that was installed in 2010 that eliminates flaring during normal refinery operations. The flare gas recovery system routes recovered gases to the refinery fuel gas system, so that flaring events are infrequent.

4.9 Transfer (Loading/Unloading) Terminals

4.9.1 General Operation and Background

The Receiving, Pumping and Shipping Process Area covers facilities at the refinery that transfer raw materials, intermediates, and finished products. There are seven transfer terminals at Phillips 66.

- Railcar Loading Rack for Gaseous Products
- Railcar Loading Rack for Liquid Products
- Truck Loading Rack for Gaseous Products
- Truck Loading Rack for Liquid Products
- Ethanol Unloading Facility
- Crude Unloading Facility
- Marine Terminal

Railcar Loading Rack for Gaseous Products

The railcar loading rack is used to ship gaseous products to market such as liquefied petroleum gas (LPG), butane and propane. The loading rack is considered a "grandfathered" source because no NSR approval orders have been issued for construction or modification of the facility. There are no specific regulations applicable to gaseous product loading activities at the railcar loading rack. In general, loading operations are done using closed systems with atmospheric vents to prevent over pressurization.

Railcar Loading Rack for Liquid Products

The railcar loading rack is used to ship and receive liquid intermediates and liquid products such as diesel, jet fuel, and heating oil. The loading rack is considered a "grandfathered" source because no NSR approval orders have been issued for construction or modification of the facility. The facility is not equipped to handle high vapor pressure products such as gasoline. There are no specific regulations applicable to liquid product loading activities at the railcar loading rack. In general, products loaded have low vapor pressures that result in relatively low VOC emission rates.

Truck Loading Rack for Gaseous Products

The truck loading rack is used to ship gaseous products to market such as liquefied petroleum gas (LPG). The truck rack is considered a "grandfathered" source because no NSR approval orders have been issued for construction or modification of the facility. There are no specific regulations applicable to gaseous product loading activities at the truck loading rack. In general, loading operations are done using closed systems with atmospheric vents to prevent over pressurization.

Truck Loading Rack for Liquid Products

The truck loading rack is used to ship liquid products to market such as gasoline, diesel, jet fuel, and heating oil. This facility is commonly referred to as the "Gasoline/Diesel Truck Rack" or simply the "Truck Rack" because it is serves as the primary means of shipping gasoline and diesel to the Pacific Northwest market when it is not shipped via pipeline. The truck rack was originally constructed for top loading. In 1990 it was modified to bottom loading and a vapor combustion device was installed to control VOC emissions that occur when gasoline vapors are displaced from cargo tanks during product loading. This modification was approved under OAC 265. The facility is also regulated under 40 CFR 63 Subpart CC, NWCAA Section 580 and Chapter 173-491 WAC.

Ethanol Truck Unloading Facility

The ethanol unloading facility was constructed in 2012 to unload ethanol from trucks and transfer to a dedicated ethanol tank (70x1). Both the ethanol unloading facility and Tank 70x1 were approved under OAC 1111. Ethanol is not a HAP regulated under 40 CFR 63 Subpart CC and there are no state or local regulations pertaining to the unloading facility, except that the new drain at the ethanol unloading facility is subject to 40 CFR 60 Subpart QQQ for VOC emissions. See Tank 70X1 for information on regulations applicable to the ethanol tank.

Crude Unloading Facility

The crude unloading facility was constructed in 2013 to unload readily available mid-continental crude oils delivered via railcar. The facility can unload 54 railcars at a time with vapor balancing and vacuum breaker equipment to control vapors. The facility was approved under OAC 1152. There are no specific regulations pertaining to the crude unloading facility other than 40 CFR 63 Subpart CC requiring HAP control from equipment leaks and 40 CFR 60 Subpart QQQ requiring oily wastewater systems to be controlled to mitigate VOC emissions.

Marine Terminal

The marine terminal ships and receives a variety of commodities at the marine dock including crude oil and refinery intermediates, as well as finished products such as jet fuel, diesel, and gasoline. The facility is considered a “grandfathered” source because it was constructed and has not been modified in a manner that would trigger new source review. In 2002, the NWCAA issued OAC 733a. This was a revision to the original approval order for the Ferndale Upgrade and Clean Fuels Projects. This revision included a limit on the amount of gasoline that could be loaded at the marine terminal to 10 million barrels in any 12-month period. It also established a VOC emission limit at the marine terminal of 819 tons in any 12-month period. The current version of this order, OAC 733f includes these limits which are listed in Section 5.9 of the AOP.

4.9.2 Construction and Permitting History

NWCAA Order of Approval to Construct 265a - Modification to Truck Rack

Original issuance January 26, 1990. Revised June 9, 2016.

Modifications to the truck loading rack include retrofitting the rack from top to bottom loading and installing a vapor recovery and vapor combustion device. This OAC has two conditions:

Condition 1: VOC emissions from the vapor combustor are limited to 35 milligrams per liter of gasoline transferred with compliance demonstrated through biennial source testing. This requirement is incorporated into the AOP without gap-filling.

Condition 2: Visual emissions from the vapor combustor are limited to 10% opacity as determined by EPA Method 9. This requirement is incorporated into the AOP with MR&R gap-filled by a common visual emissions monitoring program for the refinery.

NWCAA Order of Approval to Construct 1111 - Ethanol Unloading Facility

Original issuance February 16, 2012. No revisions.

This OAC approved the new truck ethanol unloading facility including a truck unloading pad, pumping equipment and Tank 70X1 for storing ethanol. The ethanol is used as a blending stock in gasoline. OAC 1111 has two conditions.

Condition 1: Requires Tank 70X1 to be equipped with an internal floating roof and both primary and secondary seals. This requirement is included in AOP Section 5.12: Storage Vessels.

Condition 2: A startup notice is required to be submitted for the new ethanol unloading facility. On March 1, 2013, the NWCAA received notice that the facility began operating on February 22, 2013. This one-time only requirement has been completed and it not listed in the AOP.

NWCAA Order of Approval to Construct 1152 – New Crude Unloading Facility

Original issuance June 7, 2013. No revisions.

OAC 1152 approved construction of the Crude Unloading Facility to transfer crude oil from railcars to existing storage tanks at the refinery. The project included construction of a rail spur, a railcar unloading area and associated piping, conveyance, and spill containment systems. The facility has the capacity to simultaneous unload up to 54 railcars. The OAC requires that unloading be done without VOC leaks above 500 ppm using closed vent and vapor balancing systems. The OAC also requires an LDAR program on equipment components at the facility, and that the oily wastewater vents be controlled.

All the requirements of OAC 1152 are included in the AOP except Condition 8 that is a startup notice for the Crude Unloading Facility. On November 21, 2014, the NWCAA received a letter from the refinery stating that the Crude Unloading Facility began operating on November 18, 2014. This one-time only startup notice has been completed and is not listed in the AOP.

4.9.3 Regulatory Applicability

The requirements applicable to the gasoline/diesel truck rack are somewhat complex because there are elements that apply to the vapor recovery system, vapor combustion device, the performance of the truck cargo transport tanks and LDAR requirements for fugitive leaks from equipment components. As indicated by the operating permit, the truck rack is subject to the SIP approved version of NWCAA 580.4 and 580.10, WAC 173-491, and 40 CFR 63 Subpart CC that references the requirements of 40 CFR 63 Subpart R. Many of these requirements overlap. The following is a summary of these requirements.

The truck rack is required to capture gasoline vapors displaced as the truck cargo tanks are loaded and the vapors destroyed with a vapor combustion device. When diesel is being loaded it is assumed that the tank previously held gasoline and those gasoline vapors will need to be captured and controlled. During loading the vapor recovery system must be leak tight and the overpressure valves set to remain closed. In addition, truck cargo tanks are required to be leak tightness tested every year and the refinery is required to keep a copy of the annual cargo tank leak tightness certification for each tank that is loaded at the truck rack. The vapor combustion device must reduce emissions to less than 10 mg total organic compound emissions per liter of gasoline transferred and biennial source testing is conducted to ensure compliance. For ongoing compliance, the combustion temperature of the combustion device is continuously monitored, and propane is used as a supplemental fuel to assure that the temperature is at or above 450°F.

40 CFR 60 Subpart J for SO_2 is applicable to the combustion device because it combusts hydrocarbon gas generated at the refinery. On April 4, 2003, the EPA approved an alternative monitoring plan (AMP) for compliance with Subpart J at Phillips 66 truck rack because it is impractical to operate a fuel gas hydrogen sulfide monitoring system in the truck rack vapor recovery system (Attachment A). This AMP is included in AOP terms in Section 5.9.

The truck rack is not directly subject to 40 CFR 60 Subpart XX, because it was not constructed and has not been modified or reconstructed since the December 17, 1980, the applicability date of the rule.

40 CFR 63 Subpart CC requires that the marine terminal meet the requirements of 40 CFR 63 Subpart Y. Because annual HAP emissions at the marine terminal are less than the 10/25 tpy thresholds, and because annual gasoline loading is below 10 million barrels and annual crude oil loading is below 200

million barrels; the marine terminal is not required to control emissions beyond employing submerged filling when loading commodities with vapor pressures that exceed 1.5 psia. The requirement for submerged filling was added to Subpart CC in 2015 as part of the refinery sector rule revisions.

In accordance with 40 CFR 63 Subpart CC, equipment components at the marine terminal that are in HAP service are required to be under a LDAR program.

4.10 Reciprocating Internal Combustion Engines (RICE)

4.10.1 General Operation and Background

There are numerous stationary reciprocating internal combustion engines (RICE) located throughout the refinery. All these engines are considered in dedicated emergency service, and they are infrequently operated other than during monthly maintenance and readiness testing. No NSR approvals have been issued for these engines because NWCAA Section 300 categorically exempts emergency RICE from NSR. There are federal regulations that apply to the RICE located at the refinery. Refer to the following Statement of Basis sections above for detailed information on these engines:

- Section 3.1.6 - NSPS 40 CFR 60 Subpart IIII for compression-ignition RICE
- Section 3.2.2 – MACT 40 CFR 63 Subpart ZZZZ for compression-ignition RICE
- Section 3.2.2 – MACT 40 CFR 63 Subpart PPPPP for spark-ignition octane test RICE

4.11 Effluent Collection, Conveyance and Treatment

4.11.1 General Operation and Background

Effluent collection, conveyance, and treatment includes wastewater collected by process drains, conveyed in sewer lines (both oily and phenolic), temporarily stored in tanks, treated at the refinery's wastewater treatment plant, and other activities related to handling of wastes such as treatment plant sludge and wastes from turnaround activities. Refer to Figure 4-13 for a process flow diagram of wastewater treatment at the refinery.

Wastewater collected at process units and drawn from petroleum storage tanks is collected by individual drain systems that empty to sewer trunk lines. These trunk lines flow to lift (pump) stations for conveyance to wastewater storage tanks prior to treatment. Wastewater treatment is done through a series of devices that provide physical, chemical, and biological treatment. Wastewater is physically treated by routing to an API Oil/Water Separator then to an Induced Gas Flotation Unit via closed sewers. Water leaving the Induced Gas Flotation Unit is biologically treated in a moving bed biological reactor (MBBR) and activated sludge units to further remove organic compounds. The treated wastewater is then clarified and combined with non-process surface runoff (storm water) prior to discharge into the Georgia Strait. The wastewater treatment plant is regulated under a NPDES-permit

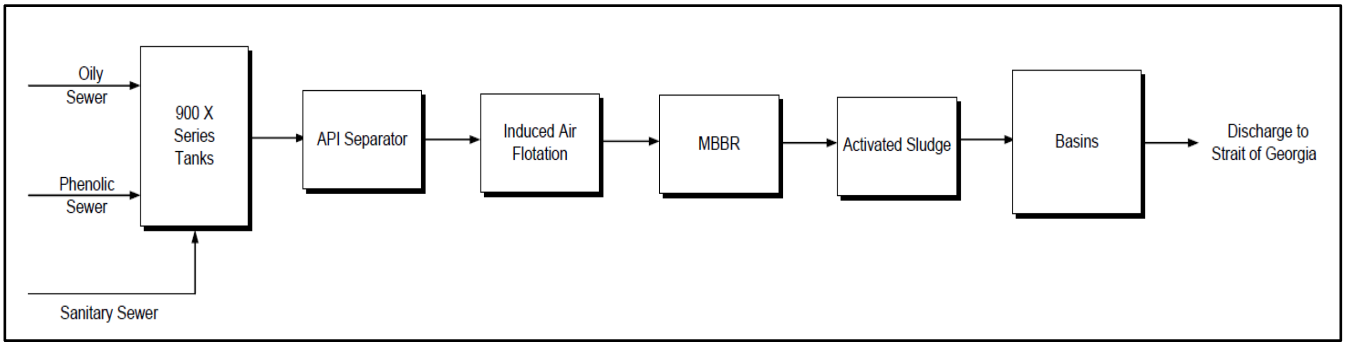

Figure 4-13 Wastewater Treatment Plant

that is not part of the AOP. Oil recovered at the treatment plant is recycled to refinery process units and solids in the recovery oil are removed, concentrated, and shipped off-site.

4.11.2 Construction and Permitting History

The basic configuration of the oily wastewater effluent system was established during original refinery construction in 1953. Since initial construction, sewers have been extended to new process units, several tanks were added to replace open storage basins, and emission controls have been installed on various waste management units.

In 1990, the EPA promulgated benzene waste operations NESHAP under 40 CFR 61 Subpart FF (BWON). This federal regulation required phase in of vapor control systems of benzene containing waste at refineries, primarily related to oily wastewater collection, conveyance, and treatment systems. In anticipation of future emission control requirements imposed by BWON, the refinery installed various vapor control strategies including seals on hatches, carbon adsorption units on vents, and covers on the API Separator. The refinery also constructed new floating storage tanks and modified other existing storage tanks to improve the control of emissions from oily wastewater.

On August 2, 1995, the NWCAA issued OAC 559 for the installation of vapor control equipment on select benzene waste management units associated with the oily wastewater effluent system. The OAC was revised on June 9, 2016, to OAC 559a, which has no applicable requirements and is not listed in the AOP.

On December 28, 2000, the NWCAA issued OAC 752 for installation of a dome roof on the wastewater treatment plant roughing filter. The filter was decommissioned by December 31, 2005, as required by the Consent Decree. Because OAC 752 contains no applicable requirements and does not apply to any existing equipment at the refinery, it is not listed in the AOP.

On February 6, 2001, the NWCAA issued OAC 756 approving portable reactor tanks utilizing recirculating air to biologically decompose sludge with vents controlled by activated carbon. The system was installed, never put into service, and subsequently decommissioned within a year of OAC issuance. On June 10, 2016, the NWCAA issued a letter stating that OAC is null and void due to the refinery not completing the project within the 18-month NSR prescribed time period. Consequently, OAC 756 is not listed in the AOP.

In 2007, the wastewater treatment plant infrastructure was upgraded including installation of the MBBR and activated sludge units. These upgrades were required by the Consent Order and helped ensure stable wastewater treatment plant operation. No NSR approval orders were issued by the NWCAA for these upgrades.

OAC 314 is the only approval order that has been issued that includes applicable requirements for oily wastewater effluent handling equipment at the refinery. This OAC was issued in 1991 for construction of new wastewater storage tanks, and for modifications to other tanks that store wastewater. A detailed discussion regarding the project approved under OAC 314 and its subsequent revision to OAC 314a is included in this document under Storage Vessels. The requirements of OAC 314a have been incorporated in the AOP.

4.11.3 Regulatory Applicability

Light hydrocarbons dissolved in or floating on wastewater have the potential to evaporate and discharge to the atmosphere. For the most part these emissions are contained and controlled under the refinery-wide, federally regulated Benzene Waste Organic NESHAP (BWON) program prescribed under 40 CFR 61 Subpart FF. This containment and control program is supplemented by two other federal regulations; NSPS 40 CFR 60 QQQ and Refinery MACT 40 CFR 63 Subpart CC, as applicable.

The BWON program is required under Subpart FF because Phillips 66 has greater than 10 megagrams per year of benzene in its wastewater and other wastes. Refinery MACT regulations under Subpart CC include an overlap provision that requires the BWON program for the control of hazardous air pollutants (HAPs). Therefore, AOP Terms that cite Subpart FF also cite Subpart CC.

BWON regulation under Subpart FF requires controls and work practices to reduce benzene emissions from equipment handling oily wastewater and other benzene containing wastes throughout the refinery. This includes requirements on final disposition of waste, waste treatment criteria, waste generation tracking, and controls on waste handling activities such as vacuum trucks and cleanup operations. Equipment that does not handle benzene containing waste and equipment at the last stage of treatment are not required to be controlled. Most drains and sewers at the refinery must be sealed. This includes water seals on drain p-traps, seals on sewer hatches, and activated carbon adsorption beds to control emissions from sewer vents. Storage tanks and portions of wastewater treatment devices (Oil/Water Separator) are fitted with floating roofs to control emissions.

Unlike Subpart FF and CC that target HAP emissions, NSPS Subpart QQQ regulates VOC emissions. Drain systems constructed, reconstructed, or modified after May 4, 1987, at the refinery are subject to Subpart QQQ. Similar to BWON, drains system subject to Subpart QQQ must be sealed to prevent emissions to the atmosphere. However, Subpart QQQ has more stringent inspection requirements than those required under BWON. Refinery MACT overlap provisions allow MACT Group 1 waste streams that are also subject to Subpart QQQ to comply only with the BWON requirements. If it is not considered a Group 1 waste stream under MACT, the more stringent requirements of Subpart QQQ apply. There are four individual drain systems at the refinery where the requirements of Subpart QQQ apply.

4.12 Storage Vessels (Tanks)

4.12.1 General Operation and Background

The general operation of refinery storage systems and applicable regulations are described in Section 3 above.

4.12.2 Construction and Permitting History

The basic configuration of the storage vessels (tanks) was established during original refinery construction in 1953. Most of the tanks are located in the tank farm on the eastside of the refinery. The following is a summary of the storage tank projects that have gone through NSR by the NWCAA.

NWCAA Order of Approval to Construct 34 (OAC 34) – Construction of External Floating Roof Tank 1340X117 and Butane Pressure Vessel 200X100

Original issuance July 20, 1971. No revisions.

OAC 163 is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 161 - Installation of Internal Floating Roofs on Tanks 100X93, 100X94 and 100X96

Original issuance June 16, 1975. No Revisions.

On September 27, 2016, the refinery informed the agency that Tank 100X96 was taken out of service with no plan to put it back into service. Therefore, Tank 100X96 is not listed in the AOP.

OAC 161 is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 163 – Construction of External Floating Roof Tank 6000x1 for Crude Oil

Original issuance August 15, 1975. No revisions.

OAC 163 is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 196 – Construction of Internal Floating Roof Tank 100x99 for Recovered Oil

Original issuance August 12, 1977. No revisions.

OAC 196 is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 314a - Tank Construction and Upgrade Project.

Original issuance August 21, 1991. Revised October 2, 2002.

The project included construction of three new 90,000-barrel, external floating roof tanks (900x1, 900x2, 900x3) to store wastewater prior to the oily wastewater treatment plant. The new storage allowed closure of several open wastewater storage basins. The project also included retrofitting two external floating roof tanks with secondary seals (100x92 and 100x95) and upgrading two tanks to internal floating roof tanks (300x40 and 100x98).

OAC 314a does not have any applicable requirements for new tanks 900x1, 900x2, and 900x3 because they are required to be constructed and operated under federal standards 40 CFR 60 Subpart Kb and/or 40 CFR 61 Subpart FF, where applicable.

OAC 314a includes requirements for tanks 300x40, 100x98, 100x92, and 100x95 that were retrofitted as part of this project. These are included as specifically applicable requirements in the AOP.

NWCAA Order of Approval to Construct 715a – Construct the Splitter Tower at the Alkylation Unit.

Original issuance December 3, 1999. Revised October 2, 2002.

OAC 715 and its subsequent revision OAC 715a, approved a project involving construction of a new splitter tower (debutanizer) at the Alkylation Unit designed to remove butane from gasoline produced from the TCCU. The project resulted in a change in service to tanks 1340X115, 550X101, and 300X44. Past agency records indicate the change in service to Tank 300X44 resulted in the tank being modified under NSPS 40 CFR 60 Subpart Kb. A review of this matter during the 2017 AOP renewal found that there were no physical modifications to the tank during this project, and that the tank was already capable of accommodating high vapor pressure liquids as an external floating roof equipped with primary and secondary seals. Therefore, the change in service of Tank 300X44 did not result in the tank being subject to 40 CFR 60 Subpart Kb. In summary, the project did not result in an NSPS construction, modification, or reconstruction to any of the tanks listed in the OAC, i.e., 1340X115, 550X101, or 300X44.

OAC 715a is considered narrative with no applicable requirements for storage tanks and is not included in the AOP.

NWCAA Order of Approval to Construct 736a – Construction of Internal Floating Roof Tank 400X1

Original issuance May 25, 2000. Revised October 2, 2002.

OAC 736a is considered narrative with no applicable requirements and is not included in the AOP.

NWCAA Order of Approval to Construct 1322 – Construct crude storage tank and fuel oil storage tank.

Original issuance August 5, 2019. The tanks were never constructed and therefore, under NWCAA 300.11(A) the OAC is invalid.

NWCAA Order of Approval to Construct 1356 – Install secondary seal and fugitive emission controls on tank 550x100 to allow flexibility to store higher TVP material.

Original issuance October 5, 2020.

On February 15, 2021, the refinery informed the agency that Tank 550x100 had begun filling; therefore, the secondary seal and fugitive controls had been installed and Phillips 66 had complied with the initial notification requirement.

5 Air Operating Permit Administration

In developing the AOP for Phillips 66, NWCAA developed assumptions for the AOP and established permit elements. Assumptions are discussed in Section 5.1 and permit elements are presented in Section 5.2.

5.1 Permit Assumptions

The following describes the assumptions the NWCAA used in developing this Statement of Basis and AOP.

5.1.1 One-Time Only Requirements

Applicable requirements that were satisfied by a single past action on the part of the source are not included in the AOP but are discussed in the Statement of Basis. Regulations that require action by a regulatory agency, but not of the regulated source are not included as applicable permit conditions.

5.1.2 "Narrative" Orders of Approval to Construct (OAC)

The following Orders of Approval to Construct (OAC) issued by the NWCAA under the minor new source review program have not been incorporated into the AOP. Because they are narrative in content, they do not contain any specific conditions that are considered specifically applicable requirements under the Title V program.

- OAC 34 (July 20, 1971): Tank 1340x117 construction
- OAC 49 (January 29, 1972): Supplemental Crude Heater (1F-1A) construction
- OAC 161 (June 16, 1975): IRF roofs on tanks 100x93, 100x94 and 100x96. Tank 100x96 was taken out of service on September 27, 2016.
- OAC 163 (August 15, 1975): Tank 6000x1 construction
- OAC 185 (July 15, 1976): SRU #1 construction
- OAC 196 (August 12, 1977): Tank 100x99 construction
- OAC 715/715a (revised October 2, 2002): #3 Reformer construction
- OAC 736/736a (revised October 2, 2002): Tank 400x1 construction
- OAC 864/864a (revised June 9, 2016): #3 Reformer OAC cleanup
- OAC 1356 (10/7/2020): Tank 550x100 service change

5.1.3 Superseded Requirements

Requirements in permits (OACs) that have been superseded are not considered applicable requirements, and therefore are not included in the AOP.

5.1.4 Federal Enforceability

Federally enforceable requirements are terms and conditions required under the Federal Clean Air Act (FCAA) or under any of its applicable requirements. Local and state regulations become federally enforceable by formal approval and incorporation into the State Implementation Plan (SIP) or through other delegation mechanisms. Federally enforceable requirements are enforceable by the EPA and citizens. All applicable requirements in the permit including standard terms and conditions, generally applicable requirements, and specifically applicable requirements are federally enforceable unless identified in the permit as "state only" meaning they are enforceable only by the state.

Permit terms list citations of an underlying requirement followed by a date in parentheses. The date represents the promulgation date for federal regulations (date of final rule publication in the Federal register), the effective date for state WAC regulations and the board adoption date for NWCAA regulations. In some cases, there are two dates listed for a particular citation. When this is the case, one date is the federally enforceable requirement because it has been adopted into the Washington State SIP, and the other date is the current version of the regulation that has not yet been adopted into the SIP. The date associated with an OAC, or PSD permit represents the issuance date of that permit. Federal regulations are always federally enforceable, therefore, citation date for federal regulations is the most recent date of promulgation.

Chapter 173-401 WAC is not federally enforceable although the requirements of this regulation are based on federal requirements for the air operating permit program. Upon issuance of the permit, the terms based on Chapter 173-401 WAC will become federally enforceable for the source.

5.1.5 Future Requirements

Applicable requirements that have been promulgated with future compliance dates are included in the permit with the compliance date listed in the permit term. Requirements that are not applicable until triggered by an action, such as the requirement to file a Notice of Construction application prior to building a new emission unit, are included in standard terms and conditions sections of the permit.

5.1.6 Alternative Operating Scenarios and Compliance Options

The source did not request emissions trading provisions or specify more than one operating scenario in the air operating permit application; therefore, the permit does not address these options as allowed under WAC 173-401-650. There are certain emission units that are permitted to operate in different modes; for those units, both scenarios are written into the permit with a recordkeeping requirement to document under which scenario the emission unit is operating. For example, the fluidized catalytic cracking unit normally operates under partial burn mode. However, the FCCU may be operated under total burn mode, which is defined in the permit. This permit does not condense overlapping applicable requirements (streamlining) nor does it provide any alternative emission limitations. The permit includes an alternative monitoring plan (AMP) for the SO_2 from the Truck Loading Rack, TRS sampling at the flare, and for visual and particulate emissions from the FCCU. The AMPs are included in Attachment A of this Statement of Basis.

5.1.7 Gap-filling and Sufficiency Monitoring

Title V of the Federal Clean Air Act is the basis for 40 CFR Part 70, which is the basis for the State of Washington air operating permit regulation, Chapter 173-401 WAC. Title V requires that all air pollution regulations applicable to the source be called out in the air operating permit for that source. Title V also requires that each applicable regulation be accompanied by a federally enforceable means of "reasonably assuring continuous compliance". 40 CFR Part 70 and WAC 173-401-615 all contain a "gap-filling" provision to address situations where no monitoring is present. 40 CFR Part 70.6(c)(1) and WAC 173-401-630(1) contain authority to address situations where monitoring exists but is deemed to be insufficient. NWCAA relied upon these authorities to add monitoring where needed to the air operating permit (AOP).

Most cases where monitoring needed to be added were older regulations, permits and NWCAA tank requirements that contained no monitoring. For example, NWCAA used its gap-filling authority to add monitoring for the 20% visible emission standard, NWCAA 451.1. The term "***Directly Enforceable***" is included in each AOP term where NWCAA added gap-filling. Table 5-1 lists where in the AOP NWCAA used its gap-filling monitoring authority.

There were also some limited cases where monitoring did exist but was found to be insufficient. NWCAA used its sufficiency monitoring authority (WAC 173-401-630(1)) to add monitoring in those cases. "***Directly Enforceable***" is included in the AOP term when NWCAA used its authority to supplement insufficient monitoring. Table 5-1 lists terms in the AOP where NWCAA used its sufficiency monitoring authority.

The type and frequency of monitoring added under the authorities in WAC 173-401-615 and WAC 173-401-630(1) were set based on the following factors:

1. Historical Compliance – NWCAA reviewed the facility's past compliance with the underlying requirement. This information helped inform the decision about monitoring frequency and stringency.
2. Margin of Compliance – The margin of compliance is a measure of whether the facility can easily achieve compliance with a requirement, or whether they operate close to an exceedance. NWCAA considered the facility's margin of compliance for each underlying requirement in setting monitoring for that requirement.
3. Variability of Process and Emissions – Processes that vary their production rates and/or emissions over time (e.g., batch loading of grain silos, VOC emissions from lumber drying kilns) require different monitoring than steady-state processes. NWCAA considered process and emission variability in setting monitoring.
4. Environmental Impact of a Problem – Exceedances of some permit requirements have greater environmental consequences than others. For example, a problem that causes an exceedance of a refinery sulfur plant limit could have a greater environmental impact than failing to use ultra-low sulfur diesel at an emergency generator. NWCAA considered the environmental impact of a problem in setting monitoring.
5. Clarity and Complexity – The requirements that apply to AOP facilities are numerous, varied, and can be complex. The greater number, variety, and complexity of requirements, the harder it is for a facility to understand and comply. NWCAA's goal is to write clear, concise permits facilities can understand. To help achieve this goal, when possible, NWCAA aligned additional monitoring with monitoring that the facility is already performing. This approach required careful thought. NWCAA reviewed the monitoring the facility is already performing to see if it was adequate to stand-in as monitoring for the permit term, and only used it if deemed adequate. For example, an older storage tank may have a NWCAA construction permit that didn't list monitoring. The same tank may also be subject to 40 CFR 60 Subpart Kb. Subpart Kb monitoring would only be used as the gap-filled (or sufficiency monitoring) if found it was adequate to show compliance with the construction permit.

Table 5-1 Gap-filling under WAC 173-401-615

AOP Terms	Description	Monitoring
4.2	Operation & maintenance	Monitor, keep records & report
4.3-4.6	Nuisance (contaminants, odors, PM, fugitives)	Written air contaminant response plan
4.7-4.17, 5.2.1-2, 5.2.33, 5.4.2, 5.6.3, 5.6.17, 5.7.3, 5.7.13, 5.8.1, 5.8.14, 5.9.1	Visible emissions	Visible emission observation monitoring
4.18	Weight/heat rate standard – sulfur compounds	Report refinery calendar monthly average SO_2, lb/MMBtu
4.19-4.21	Emissions of sulfur compounds	Monitor & record concentration of stack SO_2, or alternately, fuel gas H_2S

AOP Terms	Description	Monitoring
4.22-4.23	Sulfur in fuel	Retain fuel specifications & purchase records
4.25	O & M for VOC Equipment	Maintain records
5.2.15	Ammonia emissions	Monitor, keep records & report
5.2.23-24, 5.3.11	Heater Combustion	Monitor firing rate
5.2.26	CO boiler capacity	Report fuel use
5.2.29	VOC reduction	Maintain records
5.1.1, 5.2.30-31, 5.3.1, 5.4.1, 5.6.1, 5.6.16, 5.7.1-2, 5.7.11-12, 5.8.13	Fuel use	Certify type of fuel use
5.8.5	Heating value	Maintain records
5.9.3-4, 5.9.9-13, 5.9.15, 5.9.20	VOC control	Monitor, keep records & report of source testing
5.12.7, -11, -25, -30, -37	VOC control	Monitor, keep records & report of tank inspections

Table 5-2 Sufficiency Monitoring under WAC 173-401-630(1)

AOP Terms	Description	Monitoring
4.1	Required monitoring reports	Reporting periods identified
5.2.3	Opacity	Follow FCCU Alternative Monitoring Plan
5.6.2	Heater firing rate	Monitor and record firing rate
5.8.11	Flare Management Plan	Submit plan revisions to NWCAA
5.8.15	H2S limit for flares	Report when flare exceeds 162 ppm
5.12.8-10, -26-29, -38-42	VOC control	Monitor, keep records & report of tank inspections
6.2.1- 6.2.3, 6.2.7	LDAR	Clarification on how to calibrate

5.2 Permit Elements

The permit is organized in the following sequence:

- Permit Information
- Attest
- Table of Contents

- Section 1 - Emission Unit Descriptions
- Section 2 - Standard Terms and Conditions
- Section 3 - Standard Terms and Conditions for NSPS and NESHAP
- Section 4 - Generally Applicable Requirements
- Section 5 - Specifically Applicable Requirements
- Section 6 – Commonly Referenced Requirements
- Section 7 - Inapplicable Requirements

5.2.1 Permit Information and Attest

The Permit Information section identifies the source, the responsible corporate official, and the agency personnel responsible for permit preparation, review, and issuance. The Attest section provides authorization by the NWCAA for the source to operate under the terms and conditions contained in the permit. The Emissions Unit Descriptions section lists the significant emissions units, associated control equipment, years that equipment was constructed, reconstructed, or modified, a high-level list of the underlying requirements, and general information about the equipment such as size, type, capacity, and configuration.

5.2.2 Emission Unit Identification

AOP Section 1 entitled "Emission Unit Identification" is a non-enforceable section of the permit that provides relevant information on significant emission units at the refinery. It includes emission unit identification numbers, size of the unit, control equipment where applicable, fuel type, applicable regulations, and other related comments. The emission unit identification number commonly used at the refinery is the process unit/area number followed by the equipment number.

5.2.3 Standard Terms and Conditions

The Standard Terms and Conditions section contains administrative requirements and prohibitions that do not have ongoing compliance monitoring requirements. The citations contained in this section provide a legal basis for the Standard Terms and Conditions. Often requirements are paraphrased. In this case the language of the cited regulation takes precedence over the paraphrased summary. For understanding and readability, the terms and conditions have been grouped by function where similar requirements from State and NWCAA regulations are grouped together. Many of the requirements in this section are only applicable when triggered by an action.

5.2.4 Standard Terms and Conditions for NSPS and NESHAP

The Standard Terms and Conditions for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutant (NESHAP) specifies administrative requirements or prohibitions with no ongoing compliance monitoring requirements. The conditions in this section are from Subpart A General Provisions of 40 CFR Parts 60, 61, and 63. They apply specifically to the affected sources, affected facilities, or stationary sources subject to NSPS and NESHAP standards. The affected sources, affected facilities, or stationary sources are identified in Section 5 of the permit including a reference to the Standard Terms and Conditions for NSPS and NESHAP.

5.2.5 Generally Applicable Requirements

The Generally Applicable Requirements section identifies requirements that apply broadly to the refinery. These requirements are found in general air pollution rules such as NWCAA Regulation or the Washington Administrative Code (WAC).

The tables in Section 4 and Section 5 of the permit are organized as follows. The first column lists the permit term number and pollutant regulated by the underlying requirement. If the underlying requirement limits the type of fuel or the amount of fuel that can be combusted, the terms say "fuel" instead of a specific pollutant. The permit terms are numbered consecutively within each process area at the refinery.

The second column in the permit term lists the underlying legal citation for the requirement. This legal citation is federally enforceable unless listed as "state only". The third column provides a paraphrased description of the requirement. This paraphrase is not intended to be complete or enforceable as written. The paraphrased text serves as a descriptive summary of the requirement only.

The last column is a summary of the monitoring, recordkeeping, and reporting obligations of the underlying requirement. Similar to the third column, the text in the monitoring, recordkeeping and reporting column is a paraphrase of the cited requirement and is not intended to be complete or enforceable as written. It is included in the term as a descriptive summary only. Enforceability of the permit term is based on the citation of the underlying requirement in the second column of the table.

When the monitoring, recordkeeping and reporting column includes a "***Directly Enforceable***", this indicates that the monitoring, recordkeeping, and reporting text below that statement has been gap-filled under the agency's Title V gap-filling authority. Gap-filling is done when the underlying requirement lacks specifics regarding the method required to demonstrate compliance.

5.2.6 Specific Requirements for Emission Units

This section lists applicable requirements that specifically apply to the emission units at the refinery. The emission units are grouped by process area. The emission limitations, and monitoring, recordkeeping and reporting requirements are derived from BACT determinations and/or from applicable regulations. The format and organization of this section is the same as the table for generally applicable requirements. As with generally applicable requirements some specifically applicable requirements do not have source monitoring requirements due to the inherent nature of the source and the likelihood that the legal requirement will not be violated.

The refinery uses CEMS to continuously monitor various emission units for gaseous pollutants including NO_X and CO, as well as H_2S and TRS as surrogates for SO_2. Where CEMS are used, continuous compliance with concentration limits, and to some extent mass emission rate limits, is relatively straightforward. Pollutants not continuously monitored are visual emissions, PM, NH_3 and VOC. For these pollutants periodic opacity observations and source testing is conducted and often supplemented with continuous parameter monitoring to ensure compliance.

5.2.7 Commonly Referenced Requirements

The refinery maintains multiple similar emission units (e.g., process heaters, fugitive components, wastewater drains), each subject to certain regulatory programs. Rather than repeating the requirements for each unit in AOP Section 5, the requirements are listed once in AOP Section 6 and are referenced under the specific emission unit in AOP Section 5. AOP Section 6 entitled "Commonly Referenced Requirements" includes:

- Opacity monitoring for refinery combustion units (see Statement of Basis Section 3.10 for further discussion)
- Leak Detection and Repair (LDAR) program requirements from 40 CFR 60 Subpart VV (see Statement of Basis Section 3.1 under LDAR header for further discussion)
- Leak Detection and Repair (LDAR) program requirements from 40 CFR 60 Subpart VVa (see Statement of Basis Section 3.1 under LDAR header for further discussion)
- 40 CFR 60 Subpart QQQ requirements for individual drain systems (see Statement of Basis Section 3.1 under the wastewater header for further discussion)

- 40 CFR 63 Subpart DDDDD (Boiler MACT) requirements (see Statement of Basis Section 3.2 for further discussion)
- 40 CFR 63 Subpart CC requirements for heat exchangers (see Statement of Basis Section 3.2 under heat exchanger heading for further discussion)

Note that wastewater stream compliance under Refinery MACT 1, which refers to requirements in 40 CFR 61 Subpart FF, for all process units throughout the refinery are addressed under the Individual Drain Systems in the Effluent Plant and Sewer System in AOP Section 5.13.

5.2.8 Inapplicable Requirements

WAC 173-401-640 requires that the permitting agency issue a determination regarding the applicability of requirements with which the source must comply. The Air Operating Permit lists all requirements that are deemed inapplicable to the facility and the basis for each determination. Several regulations are listed here with applicability determinations if not evident.

40 CFR 60 Subpart NNN - VOC Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

40 CFR 60 Subpart NNN applies to distillation operations at Synthetic Organic Chemical Manufacturing Industry (SOCMI) units. Phillips 66 does not have any affected sources and does not process SOCMI listed chemicals in §60.776 at the refinery; therefore, this subpart is not applicable.

40 CFR 60 Subpart JJJJ - Stationary Spark Ignition Internal Combustion Engines

40 CFR 60 Subpart JJJJ applies to stationary spark ignition internal combustion engines that commenced construction after the specified dates and were manufactured after the specified dates. All refinery internal combustion engines burn diesel fuel and rely on the heat of compression for ignition; therefore, no refinery engines are subject to 40 CFR 60 Subpart JJJJ.

40 CFR 61 Subpart J - Equipment Leaks (Fugitive Emission Sources) of Benzene

40 CFR 61 Subpart J applies to fugitive emission sources (i.e., pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems) in benzene service and requires an LDAR program in accordance with 40 CFR 61 Subpart V. "In benzene service" is defined as contacting a fluid, either gaseous or liquid, that is at least 10% benzene by weight.

The highest benzene content stream in the refinery is in the Crude Unit at 0.57 wt% benzene. As such, no streams at the refinery are subject to 40 CFR 61 Subpart J.

40 CFR 61 Subpart BB – Benzene Operations

40 CFR 61 Subpart BB applies to benzene distribution activities at the refinery. If the liquid loaded contains less than 70 wt% benzene, the refinery is only required to comply with the recordkeeping and reporting requirements of Subpart BB. The refinery does not have any affected sources, nor the ability to distribute.

40 CFR 63 Subparts F, G, and H – Synthetic Organic Chemical Manufacturing Industry (SOCMI)

40 CFR 63 Subparts F, G, and H apply to organic hazardous air pollutants (HAPs) emissions from the manufacture of specified organic chemicals in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The refinery does not have any affected sources or listed chemicals.

40 CFR 63 Subpart Q – Industrial Process Cooling Towers

40 CFR 63 Subpart Q applies to industrial process cooling towers at major HAP sources that use chromium-based water treatment chemicals as of the proposal date (August 12, 1993). Because neither of the refinery cooling towers use chromium-based treatment chemicals as of August 12, 1993, none of the cooling towers at the refinery are considered affected sources under 40 CFR 63 Subpart Q and, hence, are not subject.

40 CFR 63 Subpart EEEE – Organic Liquids Distribution (Non-Gasoline)

40 CFR 63 Subpart EEEE applies to non-gasoline organic liquid distribution (OLD) activities at the refinery. Organic liquid for the purposes of Subpart EEEE is defined as any non-crude oil liquid or liquid mixture that contains 5% by weight or greater of a listed HAP. Organic liquids do not include gasoline (including aviation gasoline), kerosene, diesel, asphalt, heavier distillate oils, heavier fuel oils; any fuel dispensed directly to users; hazardous waste; wastewater; ballast water; or any non-crude oil with an annual average TVP less than 0.1 psia.

Under the §63.2338(c)(1) overlap provisions of Subpart EEEE, storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another 40 CFR part 63 NESHAP (MACT) are excluded from the Subpart EEEE affected source definition. Therefore, process units subject to Subpart CC, such as the truck rack, are not subject to Subpart EEEE. However, other process units that handle and transfer non-gasoline organic liquids may be subject.

The diesel truck rack and railcar rack are not subject to another MACT. However, diesel is not considered an organic liquid under Subpart EEEE; therefore, the racks are not subject to Subpart EEEE.

The propane/butane railcar and truck loading racks are not subject to another MACT standard. However, propane/butane is not a liquid at ambient pressure. As such, it is not an organic liquid and is not subject to Subpart EEEE.

Federal Mandatory Greenhouse Gas Emission Inventory Regulation

This regulation (40 CFR Part 98) applies to Phillips 66 due to its GHG emission levels and type of facility. The rule requires annual GHG inventories and reporting beginning in calendar year 2010, with reports due to EPA by no later than March 31 of the following year. This regulation is implemented in its entirety by the EPA. While this regulation is applicable, it is excluded from appearing in the AOP (and discussed in the section "Inapplicable Requirements") because it is not an "applicable requirement" as defined in WAC 173-401-200(4).

Chapter 173-485 WAC – Petroleum Refinery Greenhouse Gas (GHG) Emission Requirements

Phillips 66 elected to comply with the one-time only requirement to meet an energy intensity index (EII) that is within the 50% quartile or better for similar sized refineries using national 2006 EII data for comparison. This one-time only requirement was met on September 23, 2014, when NWCAA received the refinery's initial and final GHG annual report required under WAC 173-485-090. The refinery reported that GHG emissions for calendar year 2013 were 769,015 metric tons. The report included a letter from Solomon Associates certifying that Phillips 66 has a calculated EII that meets the Energy Efficiency Standard in WAC 173-485-040(1) and that using calendar year 2013 operational data, Phillips's EII value is equal to or more efficient that the EII value representing the fiftieth percentile EII of similar sized refineries in the United States. In accordance with WAC 173-485-050 and 173-485-090(1), Phillips has no further reporting or compliance obligations under WAC 173-485, and it is therefore not listed in the AOP.

6 Insignificant Emissions Units

Table 6-1 below lists emission units present at the refinery that are insignificant based their emission rate, size, or production rates in accordance with WAC 173-401-530 and -533. Some categorically exempt insignificant emission units as defined in WAC 173-401-532 are present but are not required to be listed herein. An emission unit cannot be considered insignificant if it is subject to any federally enforceable applicable requirement. Refinery MACT Group 2 miscellaneous process vents regulated under 40 CFR 63 Subpart CC are not insignificant because they can emit up to 13.2 tons per year of VOC and above the 2.0 ton per year insignificant emissions unit threshold listed in WAC 173-401-530

Note that the Generally Applicable requirements in AOP Section 4 apply to all insignificant emission units, although the monitoring, recordkeeping, and reporting requirements are deemed to not apply.

Table 6-1 Insignificant Emission Units

Equipment	WAC Citation
Primary Crude Process Area	
Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)
Sampling connections used exclusively to withdraw materials for laboratory analysis and testing	WAC 173-401-532(51)
Steam vents	WAC 173-401-532(87)
Vents from continuous emissions monitors and other analyzers	WAC 173-401-532(8)
Sample gathering, preparation, management	WAC 173-401-532(73)
Lube oil storage and use	WAC 173-401-532(3) and (69)
Maintenance activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
Catalytic Cracking Process Area	
FCCU Catalyst: Batch loading and unloading of solid phase catalysts	WAC 173-401-532(60)
Sampling connections used exclusively to withdraw materials for laboratory analysis and testing	WAC 173-401-532(51)
Sample gathering, preparation, management	WAC 173-401-532(73)
Maintenance Activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)
Misc. Tanks (Seal Oil, Anti-Corrosive): Storage tanks, reservoirs and pumping and handling equipment of any size limited to soaps, lubricants, hydraulic fluid, vegetable oil, grease, animal fat, aqueous salt solutions or other materials and processes using appropriate lids	WAC 173-401-532(4)

Equipment	WAC Citation
and covers where there is no generation of objectionable odor or airborne particulate matter	
Vents from continuous emissions monitors and other analyzers	WAC 173-401-532(8)
Steam vents	WAC 173-401-532(87)
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)
Alkylation Process Area	
Small tanks: Operation, loading and unloading of storage tanks, not greater than 1,100-gallon capacity, with lids or other appropriate closure, not for use with hazardous air pollutants (HAPs), maximum (max.) vp 550mm Hg	WAC 173-401-533(b)
Acid Storage Tanks: Tanks vessels and pumping equipment, with lids or other appropriate closure for storage or dispensing of aqueous solutions of inorganic salts, bases and acids excluding: (i) 99% or greater H_2SO_4 or H_3PO_4 (ii) 70% or greater HNO_3 (iii) 30% or greater HCl (iv) More than one liquid phase where the top phase is more than one percent VOCs	WAC 173-401-533(2)(s)
Sampling connections used exclusively to withdraw materials for laboratory analysis and testing	WAC 173-401-532(51)
Saturated Gas Plant: Steam vents	WAC 173-401-532(87)
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)
Open Vessel-Equipment Neutralizer: Salt baths using nonvolatile salts and not used in operations which result in air emissions	WAC 173-401-532(80)
Open Vessel-Equipment Neutralizer: Storage tanks, reservoirs and pumping and handling equipment of any size limited to soaps, lubricants, hydraulic fluid, vegetable oil, grease, animal fat, aqueous salt solutions or other materials and processes using appropriate lids and covers where there is no generations of objectionable odor or airborne particulate matter	WAC 173-401-532(4)
Alkylation Unit and Saturated Gas Plant: Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)
Vents from continuous emissions monitors and other analyzers	WAC 173-401-532(8)
Maintenance activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
Sample gathering, preparation, management	WAC 173-401-532(73)
Reformer/Diesel Hydrotreater Process Area	
#3 Reformer: Sampling connections used exclusively to withdraw materials for laboratory analysis and testing	WAC 173-401-532(51)

Equipment	WAC Citation
#3 Reformer: Steam vents	WAC 173-401-532(87)
#3 Reformer: Batch loading and unloading of solid phase catalysts	WAC 173-401-532(60)
Maintenance activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
DHT: Lube Oil Reservoirs	WAC 173-401-532(3)
Vents from continuous emissions monitors and other analyzers	WAC 173-401-532(8)
Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)
Sample gathering, preparation, management	WAC 173-401-532(73)
Sulfur Plant/Treaters Process Area	
Steam vents	WAC 173-401-532(87)
Maintenance activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
Vents from continuous emissions monitors and other analyzers	WAC 173-401-532(8)
Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)
Sample gathering, preparation, management	WAC 173-401-532(73)
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)
ESP Electrical System Vents: vents from rooms, buildings and enclosures that contain permitted emission units or activities from which local ventilation, controls and separate exhaust are provided	WAC 173-401-532(9)
Sampling connections used exclusively to withdraw materials for laboratory analysis and testing	WAC 173-401-532(51)
Treater Caustic, and Caustic Neutralization Tanks: Tanks vessels and pumping equipment, with lids or other appropriate closure for storage or dispensing of aqueous solutions of inorganic salts, bases and acids excluding: (i) 99% or greater H_2SO_4 or H_3PO_4 (ii) 70% or greater HNO_3 (iii) 30% or greater HCl (iv) More than one liquid phase where the top phase is more than one percent VOCs	WAC 173-401-533(2)(s)
Utilities	
Boiler Area Steam vents	WAC 173-401-532(87)
Boiler Area Transfer – Bag Dump: Batch loading and unloading of solid phase catalysts	WAC 173-401-532(60)

Equipment	WAC Citation
Boiler Area Slurry Basin: Demineralization and oxygen scavenging (deaeration) of water	WAC 173-401-532(61)
Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR Part 61 FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)
Maintenance activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
Firefighting Fire Foam Storage	WAC 173-401-532(52)
Miscellaneous Cooling Tower Chemical Storage Tanks: Tanks vessels and pumping equipment, with lids or other appropriate closure for storage or dispensing of aqueous solutions of inorganic salts, bases and acids excluding: (i) 99% or greater H_2SO_4 or H_3PO_4 (ii) 70% or greater HNO_3 (iii) 30% or greater HCl (iv) More than one liquid phase where the top phase is more than one percent VOCs	WAC 173-401-533(2)(s), and 532(42)
Miscellaneous Cooling Tower Chemical Storage Tanks: Polymer tanks and storage devices and associated handling equipment, used for solids dewatering and flocculation	WAC 173-401-532(117)
Miscellaneous Cooling Tower Chemical Storage Tanks: Mixing, packaging, storage and handling activities of any size, limited to soaps, animal fat, aqueous salt solutions	WAC 173-401-532(69)
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)
Sampling connections used exclusively to withdraw materials for laboratory analysis and testing	WAC 173-401-532(51)
Sample gathering, preparation, management	WAC 173-401-532(73)
Effluent Collection, Conveyance and Treatment Plant	
Polymer tote: Polymer tanks and storage devices and associated handling equipment, used for solids dewatering and flocculation	WAC 173-401-532(117)
Stormwater System	WAC 173-401-533(3)(d)
Spill Basin	WAC 173-401-533(3)(d)
Steam vents	WAC 173-401-532(87)
Storage Vessels	
1X726, 100-Barrel Sulfuric Acid Storage Tank, 2X196, 200-Barrel Caustic Storage Tank, 1X722 Sodium Silicate: Tanks vessels and pumping equipment, with lids or other appropriate closure for storage or dispensing of aqueous solutions of inorganic salts, bases and acids excluding: (i) 99% or greater H_2SO_4 or H_3PO_4 (ii) 70% or greater HNO_3 (iii) 30% or greater HCl	WAC 173-401-533(2)(s)

Equipment	WAC Citation
(iv) More than one liquid phase where the top phase is more than one percent VOCs	
Polymer Tank: Polymer tanks and storage devices and associated handling equipment, used for solids dewatering and flocculation	WAC 173-401-532(117)
Boiler Area 50X306 Storage Tank, Boiler Area 5X1244 Storage Tank, Boiler Area 20X1300 Storage Tank, Boiler Area 250X25 Storage Tank: Storage tanks, reservoirs and pumping and handling equipment of any size limited to soaps, lubricants, hydraulic fluid, vegetable oil, grease, animal fat, aqueous salt solutions or other materials and processes using appropriate lids and covers where there is no generations of objectionable odor or airborne particulate matter	WAC 173-401-532(4)
1X723 Alum Storage Tank	WAC 173-401-532(97)
Cleaning and Painting: Maintenance activities not involving installation of an emission unit and not increasing potential to emit and not otherwise subject to a federally enforceable applicable requirement.	WAC 173-401-532(74)
Other Areas	
Lab water heaters: Space heaters and hot water heaters using natural gas, propane or kerosene and generating less than five million Btu/hr	WAC 173-401-533(2)(r)
Vehicle exhaust from auto maintenance and repair shops	WAC 173-401-532(7)
Painting: Plant upkeep including routine housekeeping, preparation for and painting of structures or equipment, retarring roofs, applying insulation to buildings in accordance with applicable environmental and health and safety requirements and paving or stripping parking lots	WAC 173-401-532(33)
Drum storage: Portable drums and totes	WAC 173-401-532(42)
Fire and Emergency Response Training: Firefighting and similar safety equipment and equipment used to train fire fighters excluding fire drill pits	WAC 173-401-532(52)
Fuel Truck: Mobile transport tanks on vehicles, except for those containing asphalt	WAC 173-401-532(2)
Turnaround Equipment (Diesel Cranes, Air Compressors, Diesel Generators, Diesel Aggregate Blaster-Painting): Plant upkeep including routine housekeeping, preparation for and painting of structures or equipment, retarring roofs, applying insulation to buildings in accordance with applicable environmental and health and safety requirements and paving or stripping parking lots	WAC 173-401-532(33)
Trucks, Forklifts, Autos, etc.: Internal combustion engines for propelling or powering a vehicle	WAC 173-401-532(10)
Infirmary	WAC 173-401-532(53)
Refinery Laboratory	WAC 173-401-533(3c)
Maintenance activities not involving installation of an emission unit and not increasing potential to emit and	WAC 173-401-532(74)

Equipment	WAC Citation
not otherwise subject to a federally enforceable applicable requirement.	
Carpenter Shop	WAC 173-401-532(55)
Welding Activities	WAC 173-401-532(12)
Warehouse Drum Storage	WAC 173-401-532(42)
Warehouse Forklift Propane Tanks	WAC 173-401-532(10) and (2)
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)
Sample gathering, preparation, management	WAC 173-401-532(73)
Steam vents	WAC 173-401-532(87)
Sewer manholes, junction boxes, sumps and lift stations associated with wastewater treatment systems. Note: Sewer manholes, junction boxes, sumps and lift stations regulated under 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC are not included in this exemption.	WAC 173-401-532(120)

7 Changes to Previous AOPs

This section provides a summary of changes to the initial permit, and subsequent permits, but does not include a discussion of changes made during the current renewal. Changes incorporated into the current renewal are addressed in the main text of the Statement of Basis (Section 1).

Additional detail regarding construction permit history or issued OACs, can be found in the specific permitting documentation.

The summary is ordered from most recent change to the oldest change.

#016R2M2 issued March 3, 2022

Included references to 40 CFR §63.671 – Requirements for flare monitoring systems.

#016R2M1 issued June 15, 2020

The name of the responsible corporate official was changed from Ms. Jolie Rhinehart, previous Refinery Manager to Mr. Carl Perkins, Refinery Manager.

#016R2 issued January 1, 2018

Dates for all regulatory citations were checked and updated as necessary to reflect the most recent dates for federal, state and NWCAA regulations. New regulatory applicable requirements were added where required by the newer regulation.

Information page

The Air Operating Permit number was changed from 016R1 to 016R2 reflecting the second AOP renewal. There were no modifications to 016R1 prior to 016R2 being issued. Other dates were changed reflect the application and permit expiration timing. The Corporate Responsible Official was changed to reflect the current refinery manager.

SECTION 1 Emission Unit Descriptions

Additional information was added to the tables in Section 1 to reflect additional emission units that were added due to new regulations or due to being constructed recently. The notes in the table were improved with more information about emission units size and capacity, and brief regulatory citations were added for reference.

SECTION 2 Standard Terms and Conditions

Regulatory citations and dates were updated as necessary along with associated changes to the requirements. WAC 173-442 - Greenhouse Gas Clean Air Rule (CAR) was added to Section 2 of the AOP.

SECTION 3 Standard Terms and Conditions for NSPS and NESHAP

Regulatory citations and dates were updated as necessary along with associated changes to the requirements. This included removing requirements for startup, shutdown and malfunction plans that were no longer required under 40 CFR 63 MACT regulations.

SECTION 4 Generally Applicable Requirements

Regulatory citations and dates were updated as necessary along with associated changes to the paraphrased requirements. Gap-filled MR&R requirements imposed under WAC 173-401-615(1) were better identified by inserting “directly enforceable” above only those gap-filled requirements. Fenceline monitoring for benzene required under the refinery sector rule revisions to 40 CFR 63 Subpart CC was added to Section 4. In addition, the due dates for submitting periodic reporting were clarified. The permit terms were reorganized in the following order based on the air pollutant regulated by the permit term; VE (visual emissions), PM (particulate matter including total PM, PM_{10} or $PM_{2.5}$), SO_2, NOx, CO, NH3 (ammonia), VOC and HAP (includes TAPs).

SECTION 5 Specifically Applicable Requirements

Regulatory citations and dates were updated as necessary along with associated changes to the paraphrased requirements. This included new and revised requirements under 40 CFR 63 Subpart CC and Subpart UUU related to the refinery sector rule. It also included numerous new and revised OACs issued during the renewal period by the agency.

Gap-filled MR&R requirements imposed under WAC 173-401-615(1) were better identified by inserting "directly enforceable" above only those gap-filled requirements. The citation of NWCAA Section 104 that incorporated federal regulations by reference was removed from individual permit terms and added to the introduction portion of Section 5 instead. The permit terms were reorganized in the following order based on the air pollutant regulated by the permit term; VE (visual emissions), PM (particulate matter including total PM, PM_{10} or $PM_{2.5}$), SO_2, NOx, CO, NH_3 (ammonia), VOC and HAP (includes TAPs).

Some of the more significant changes to Section 5 included incorporating new and revised requirements under the refinery sector rule revisions to 40 CFR 63 Subpart CC and Subpart UUU. The table for the Flare System was revised to incorporate new provisions for flares due January 30, 2019, required under the refinery sector rule. The table for storage vessels (tanks) was rewritten to reflect Phillips 66's option to use the control and work practice standards under 40 CFR 63 Subpart WW as allowed under the refinery sector rule revisions. Other refinery sector rule revisions included alternative standards for emission units during startup and shutdowns activities and adding provisions to limit emissions during the opening of maintenance process vents.

Table 7-1 lists the new or revised orders that were added to the permit during the second AOP renewal. The orders include Orders of Approval to Construct (OAC), and a compliance order issued by the NWCAA. It also includes a Prevention of Significant Deterioration (PSD) permit issued by Ecology. Several OACs that have been added to the permit were revised for AOP cleanup prior to incorporation into the AOP.

Table 7-1 Orders added in AOP Renewal 2

Issued	Order	Original Project Description
September 30, 2016	OAC 733e	Ferndale Upgrade and Clean Fuels Project (new FCCU and modify Alky Unit and SRU #1)
June 9, 2016	OAC 265a	Modify Truck Loading Rack
June 9, 2016	OAC 578b	New #1 Boiler
June 9, 2016	OAC 727a	New Merox Unit
June 9, 2016	OAC 780a	Modify DHT Heater
June 9, 2016	OAC 795a	Modify Alky Unit with new Debutanizer Tower
June 9, 2016	OAC 877b	New #4 Boiler
June 9, 2016	OAC 908b	New SRU #2 and modify Crude and FCCU Units.
February 11, 2016	OAC 1232	Modify Crude Unit with a new Distillation Tower
September 9, 2015	PSD-00-02 Amd 8	Ferndale Upgrade and Clean Fuels Project (new FCCU and modify Alky Unit and SRU #1)

Issued	Order	Original Project Description
April 21, 2015	OAC 1012d	Modify Vacuum Flasher Heater with SCR
October 23, 2015	OAC 1223	New Tier III Hydrotreater Unit
October 21, 2014	OAC 1047a	Modify CO Boiler with ESNCR
July 14, 2014	Compliance Order 13	Consent Decree CO limits on the FCCU/CO Boiler
March 7, 2014	OAC 1174	Flare Infrastructure Upgrade Project
June 7, 2013	OAC 1152	New Crude Unloading Facility
February 16, 2012	OAC 1111	New Ethanol Unloading Facility and Storage Tank

One order, OAC 49 issued January 29, 1972, was removed from the AOP during the second renewal because it was deemed to be narrative with no ongoing requirements. OAC 49 was issued for construction of Supplemental Crude Heater (1F-1A).

SECTION 6 Inapplicable Requirements

The following regulations were added to the list of inapplicable requirements in Section 6 of the AOP because there were no emission units at the refinery subject to the requirements.

- 40 CFR 60 Subpart NNN - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture
- 40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

The following regulations were removed from the list of inapplicable requirements in Section 6 of the AOP.

- 40 CFR 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units has been removed because there are two utility boilers at the refinery subject to Subpart Db.
- 40 CFR 63 Subpart R - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) has been removed because the Truck Loading Rack is required to employ control requirements of Subpart R as referenced by 40 CFR 63 Subpart CC.
- 40 CFR 63 Subpart Y - National Emission Standards for Marine Tank Vessel Loading Operations was removed because the Marine Terminal is required to employ a control requirement of Subpart Y as referenced by 40 CFR 63 Subpart CC.

#016R1 issued January 1, 2011

The document was completely reformatted into the current format standard. References to the Northwest Air Pollution Authority or NWAPA were changed to the Northwest Clean Air Agency or NWCAA.

Dates for all regulatory citations were checked and updated as necessary to show the most recent dates for federal regulations and the most recent dates of effectiveness for state and local only regulations. New regulatory applicable requirements were added.

Permit Information Page

The front page of the AOP was changed to a newer format, a new logo, and the name of the agency changed to the Northwest Clean Air Agency.

The Air Operating Permit Number was changed from "016" to "016R1," reflecting the first renewal.

Various dates have been changed to reflect the revision's application and permit timing.

The Responsible Corporate Official was changed from the previous refinery manager, Mr. Gary Goodman, to the current refinery manager, Marjorie Hatter.

Attest page

The Attest page was changed to reflect current regulations and personnel changes.

SECTION 1: Emission Unit Descriptions

Process areas were renamed and updated to reflect current operations, in some cases with new units added to the refinery and others removed. A table was added to include miscellaneous individual drain systems and wastes. The individual drain system notes were simplified throughout each table and regulatory requirements were added whenever a distinction was necessary. The storage tanks were reorganized into different groups depending upon their current usage and regulatory requirements. The Cat Gas Desulfurizer (S-Zorb Unit) was moved to the alkylation process area from the sulfur plant/treaters process area and a second sulfur plant was added.

SECTION 2: Standard Terms and Conditions

Regulatory citations and dates were checked and updated wherever necessary. A permit term (2.1.10 Ambient Air and Continuous Emission Monitoring) was revised to reflect a new State Only regulation and appendix added since original permit issuance. The following permit terms were added:

2.1.11 Credible Evidence

2.2.15 Transfer or Permanent Shutdown

2.4.5 Reporting to Verify Emissions from Potential PSD Sources

The "Excess Emissions" permit term was reorganized to clarify regulatory requirements. Finally, a "Notice of Construction and Application for Approval/New Source Review" subsection was added, and new regulatory requirements were added under this topic.

SECTION 3: Standard Terms and Conditions for NSPS and NESHAP

The dates and citations were updated throughout this section. The Startup, Shutdown, and Malfunction regulatory requirements for NESHAPs in Section 3.3 were extensively rewritten and updated. Several requirements from Part 63 Subpart A, General Provisions, were added. These include:

3.3.11 Notification of Performance Tests

3.3.13 Operation and Maintenance of Continuous Monitoring Systems (CMS)

3.3.14 Continuous Monitoring Systems (CMS) Out of Control Periods

3.3.15 Continuous Monitoring Systems (CMS) Quality Control Program

3.3.16 Continuous Monitoring Systems (CMS) Data Reduction

Two permit conditions (3.3.10 Compliance with Nonopacity Emission Standards and 3.3.11 Compliance with Opacity and Visible Emission Standards) were removed because the regulations from which they were derived were vacated by the United States Court of Appeals.

SECTION 4 Generally Applicable Requirements

Regulatory citations were updated. The introductory paragraph was changed to reflect the fact that the federally approved NWCAA 365, 366 and the "Guidelines for Industrial Monitoring Equipment and Data Handling" were replaced by NWCAA 367 and Appendix A - "Ambient Monitoring, Emission Testing and Continuous Emission and Opacity Monitoring". The "Test Method" column was removed, and test methods were incorporated in the text of each condition, where appropriate. The "gap-filling" requirements in the MR&R column table description were modified to reflect that NWCAA authority is under WAC 173-401-615(1)(b) & (c), 10/17/02. There was a slight rearrangement of the permit conditions.

SECTION 5 Specifically Applicable Requirements

Section 5 was significantly revised. The introductory paragraph was changed similarly to Section 4. Regulatory citations were updated. Conditions with citations and links to the monitoring, recordkeeping, and reporting requirements for individual drain systems (40 CFR Part 61 Subpart FF and Part 63 Subpart CC) and equipment components were added to the many tables because they have general applicability to process areas or units to which they are attached. Wherever a delegated federal rule (NSPS or NESHAP) was directly cited, a citation to the NWCAA Regulation 104.2 (6/10/10) was added to clarify that the delegation had occurred.

A schedule of compliance with 40 CFR Part 63 Subpart CC requirements for the crude unit compressors 1K-1 and 1K-1A was removed since COP completed the compliance requirements. An interim schedule for compliance with 40 CFR Part 63 Subpart UUU opacity monitoring requirements was removed and a FCCU Wet Gas Scrubber Alternative Monitoring Plan was added in its place when the interim compliance requirements were fulfilled.

CAM requirements were inserted into Section 5 for control of PM/PM10 from the FCCU/CO Boiler emission unit and for control of VOCs from the gasoline/diesel truck loading vapor combustor.

The Catalytic Gasoline Desulfurization (CGD or S-Zorb Unit) was removed from the Sulfur/Treaters process area and added to the Alkylation process area. Sulfur Plant 2 was constructed in 2007. Its regulatory requirements have been added to Section 5.

Boiler #4 (22F-1E) was constructed in 2008 and its regulatory requirements have been added.

Two control equipment units for NO_X were added; an ESNCR (enhanced selective noncatalytic reduction) system was permitted for the FCCU/CO Boiler system, and SCR (selective catalytic reduction) was permitted and added to the vacuum flash heater. The regulatory requirements were included in Section 5.

In the Effluent Plant process area, the petrozyme sludge treatment tank requirements were removed since the tanks were taken out of operation. An interim compliance schedule for 40 CFR §61.348 and 40 CFR §61.353 was removed since the compliance requirements had been completed.

Storage vessel groups and tables were updated and rearranged to reflect current tank use and regulatory requirements.

A new flare gas recovery system was permitted and installed in 2010. Regulatory requirements were added to the Flare process area. Compliance plans for the emergency ground flare and the ZTOF flare were added to meet 40 CFR Subpart J requirements. These requirements were settled in the facility's Consent Decree Civil Action No. H-05-0258.

A table, 5.12 – Miscellaneous Individual Drain Systems and Wastes, was added to include the regulatory requirements for the engine lab, spills and miscellaneous waste streams, the laboratory, and solid wasted drains.

The LDAR Equipment Leak table was significantly revised to make it more complete and to include the new regulatory requirements from NSPS Subpart GGGa.

A table, 5.15 – Common Requirements: 40 CFR 60 Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems was added to streamline regulatory requirements from individual units.

Process Areas tables containing regulatory requirements from OAC 733 (including all amendments) were significantly revised because OAC 733 was amended several times since the original 2003 AOP and the newer version supersedes the older version. Therefore, OAC 733a was removed from the AOP. Fourteen additional permits (both OACs and PSD permits) were added; either because they are new since the 2003 AOP or because the original did not include the older permits.

SECTION 6 Inapplicable Requirements

Two regulatory requirements considered to be inapplicable in the original AOP were removed from the inapplicability table. These requirements are 40 CFR Part 63 Subpart CC for the Butane Isomerization Unit equipment components and 40 CFR 60 Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.

8 Public Docket

Copies of Phillips 66 Ferndale Refinery's Air Operating Permit application and technical support documents are available online at www.nwcleanairwa.gov or the following location:

Northwest Clean Air Agency

1600 South Second Street

Mount Vernon, WA 98273-5202

9 Response to Comments on Draft AOP

The only comments received during the August 10 to September 10, 2022 Public Comment Period were from Phillips 66. Comments and responses are summarized as follows.

- Comment: Correct typo on Condition 5.8.4. The condition should require that the facility record and report in a MACT report when NHVcz falls below 270 Btu/scf, not when it's above 270 Btu/scf.
    - Response: Change made as requested.

- Comment: On page 113 of the Statement of Basis, remove the date (MM DD) placeholder and replace it with the date:

  #016R2M2 issued MM DD, 2022

  Included references to 40 CFR §63.671 – Requirements for flare monitoring systems.

    - Response: Change made as requested.

- Comment: We noticed that Condition #3 from OAC 733f was not incorporated into Section 5.6 (Sulfur Recovery Plant - SRU #1) of the draft permit. Can you please add this condition where appropriate?
    - Response: Change made as requested to add Condition 3 to AOP term 5.6.4.

- Comment: In Condition 5.6.4, under Monitoring, Recordkeeping & Reporting, can the language be changed from rolling average to consecutive 12-hour and 720-hour averages, just for consistency? Although technically I suppose they mean the same thing, so it could stay as is – but just a suggestion.
    - Response: Change made as requested. The terms "consecutive" and "rolling" are equivalent in this context.

- Comment: In condition 5.2.23 (CO Boiler Auxiliary Firing Rate) – is the 109 MMBtu/hr limit intended to be a one-hour block average, starting at the top of the hour, or a 24-hour average, calculated on a 24-hour rolling basis?
    - Response: The underlying PSD permit does not provide an averaging period (neither 1-hr nor 24-hr). Historical documentation indicates 109 MMBtu/hr is the design rate of the unit. It does not indicate that this is a never-to-exceed number, even on a short-term basis. The CO Boiler is an existing, older, emission unit. Historical operation includes some short-term periods slightly over 109 MMBtu/hr. However, such fluctuations are smoothed out over a 24-hr period. A review of documentation at NWCAA and P66 did not shed any light on the averaging period intended by the manufacturer. Given the lack of clarity in documentation and the fact that using a 24-hr averaging period does not affect any conclusions in the PSD permit, NWCAA added a clarifying statement to the monitoring method in Condition 5.2.23. The revised monitoring method requires P66 to "Report monthly, the maximum hourly auxiliary firing rate of the CO Boiler calculated on a rolling 24-hour average basis".

10 Definitions and Abbreviations/Acronyms

Definitions are assumed to be those found in the underlying regulation. A short list of definitions has been included to cover those not previously defined.

An "applicable requirement" is a provision, standard, condition, or requirement in any of the listed regulations or statutes as it applies to an emission unit or facility at a stationary source.

An "emission unit" is any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant.

A “permit” means, for the purposes of the air operating permit program, an air operating permit issued pursuant to Title 5 of the 1990 Federal Clean Air Act.

“Technology-Based Emission Standard” means a standard, the stringency of which is based on determinations of what is technologically feasible considering relevant factors.

“State” means for the purposes of the air operating permit program the NWCAA or the Washington State Department of Ecology.

The following is a list of abbreviations and acronyms used in the Air Operating Permit or Statement of Basis:

AMP	Alternative Monitoring Plan
AOP	Air Operating Permit
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
Bbl	Barrel (42 U.S. gallons)
BWON	Benzene Waste Operations NESHAP (40 CFR 61 Subpart FF)
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CD	Consent Decree
CGD	Cat Gas Desulfurization (CGD/S-Zorb Process Unit)
COB	CO Boiler
COM	Continuous Opacity Monitor
CFR	Code of Federal Regulations
EPA	United States Environmental Protection Agency
DHT	Diesel Hydro Treater (Unit)
EFR	External floating roof (tank)
ESNCR	Enhanced selective non-catalytic reduction (at FCCU)
FCAA	Federal Clean Air Act
FCCU	Fluid Catalytic Cracking Unit
FGS	Flue Gas Scrubber (at FCCU)
HAP	Hazardous Air Pollutants (and TAPs)
HON	Hazardous Organic NESHAP
H_2S	Hydrogen sulfide
IFR	Internal floating roof (tank)
kPa	Kilopascals (pressure)
LEL	Lower explosive limit
LDAR	Leak Detection and Repair
LTPD	Long tons per day (2,240 pounds per day)
MACT	Maximum Achievable Control Technology (under 40 CFR 63)
EPA Method	U.S. EPA Test Method found under 40 CFR 60 Appendix A
Mg	Megagram (10^6 grams mass)
MMBtu	Million British thermal units
MR&R	Monitoring, Recordkeeping, and Reporting

MTVP	Maximum true vapor pressure
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOC	Notice of Construction
NO_X	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
NWCAA	Northwest Clean Air Agency
O_2	Oxygen
OAC	Order of Approval to Construct
OMMP	Operation, Maintenance, and Monitoring Plan (required by MACT)
PM	Particulate matter (may include PM_{10} or $PM_{2.5}$)
PM_{10}	Particulate matter less than 10 microns in diameter
$PM_{2.5}$	Particulate matter less than 2.5 microns in diameter
ppmvd	Parts per million by volume, dry
ppmw	Parts per million by weight
psia	Pounds per square inch atmospheric
PSD	Prevention of Significant Deterioration (PSD permit)
PTE	Potential to Emit (annual, unless otherwise noted)
PRD	Pressure Relief Device
QA/QC	Quality assurance/quality control
RATA	Relative Accuracy Test Audits (for CEMS under 40 CFR 60, Appendix F)
RCW	Revised Code of Washington
SCR	Selective catalytic reduction
SOP	Standard operating procedure
SRU	Sulfur Recovery Unit
SIP	State Implementation Plan
SO_2	Sulfur dioxide
RICE	Reciprocating internal combustion engines
TAB	Total annual benzene
TGU	Tail Gas Unit
TRS	Total reduced sulfur
VE	Visual emissions
VP	Vapor pressure
VOC	Volatile organic compounds
VOL	Volatile organic liquid
WAC	Washington Administration Code
WDOE	Washington State Department of Ecology, also stated as Ecology
WWT	Wastewater treatment

11 Attachment A: Alternative Monitoring Plan

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 150
Seattle, WA 98101-3140

AIR & RADIATION
DIVISION

APR 17 2019

Mr. John L. Anderson
HSE Manager
Phillips 66, Ferndale Refinery
PO Box 8
Ferndale, Washington 98248

Re: Request to Renew Alternative Monitoring Plan in Lieu of a COMS at Ferndale Refinery

Dear Mr. Anderson:

This letter is in response to your June 2017 letter submitted to the U.S. Environmental Protection Agency (EPA), Region 10 on behalf of the Phillips 66 Ferndale Refinery requesting renewal of an alternative monitoring plan (AMP) in lieu of a continuous opacity monitoring system (COMS) required by 40 CFR part 63, subpart UUU: *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units* (NESHAP UUU). We are conditionally granting your request to renew your AMP.

On December 1, 2015, Table 2 to NESHAP UUU was revised, reducing the opacity limit at the fluidized catalytic cracking unit (FCCU) at the Ferndale Refinery from 30 percent to 20 percent. (See 80 FR 75354.) Because the FCCU is controlled by a wet scrubber, which limits the effectiveness of a COMS, on March 31, 2006, EPA approved an AMP to allow the monitoring of scrubber operating parameters in lieu of the requirement to install and operate a COMS to monitor opacity. This AMP was revised on December 7, 2009. The AMP appears in the Ferndale Refinery's title V permit issued by the Northwest Clean Air Agency (NWCAA permit AOP 016R2, issued January 1, 2018) as Condition 5.2.4. and is also cited as a monitoring condition used to assure compliance with other particulate matter and opacity limits in the permit. Because the opacity limit in NESHAP UUU has changed since the AMP was last granted, it is necessary to review the AMP.

The AMP includes a minimum liquid-to-gas ratio and a maximum weight percent solids value, which are empirical values that had been established through performance testing.

In September 2015, the Washington Department of Ecology issued a prevention of significant deterioration (PSD) permit to the FCCU and wet scrubber that included a best available control technology (BACT) limit of 0.50 lb of PM_{10} (particulate matter with an aerodynamic diameter less than or equal to 10 micrometers) per thousand pounds of coke burn-off and 0.020 grains per dry standard cubic foot at 7 percent oxygen. These limits are three-hour averages, to be established by annual testing in compliance with 40 CFR, part 60, appendix A, method 5B.

Considering that the PSD BACT limit for PM_{10} that applies to the FCCU is fifty percent lower than the particulate matter limit established in NESHAP UUU, and that the PSD permit requires annual performance testing, we are renewing approval of the December 2009 AMP provided Phillips 66 applies to revise the liquid-to-gas ratio and weight percent solids values, if Phillips 66 determines, in consultation with NWCAA, that such a revision becomes necessary, based on the results of annual performance testing.

If you have any questions about this about this matter, please contact Geoffrey Glass of my staff at (206) 553-1847 or glass.geoffrey@epa.gov.

Sincerely,

Kelly McFadden

Kelly McFadden, Manager
Stationary Source Unit

Cc: Mark Buford, Executive Director, NWCAA
Toby Mahar, Compliance Manager, NWCAA (email)
Daniel Mahar, Environmental Engineer, NWCAA (email)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

DEC 07 2009

OFFICE OF
AIR, WASTE AND TOXICS

Rosanne F. Paris
Environmental Lead
ConocoPhillips Company
Ferndale Refinery
P.O. Box 8
Ferndale, Washington 98248

Dear Ms. Paris:

Re: Opacity Alternative Monitoring Plan Proposal for the Fluid Catalytic Cracking Unit (FCCU) Wet Gas Scrubber (WGS) for the Ferndale Refinery

This is in response to your letter of August 17, 2009, requesting approval of a revision to the previously approved alternative monitoring plan (AMP) dated March 31, 2006. After review of the information ConocoPhillips submitted, EPA approves your request.

ConocoPhillips requested that the approved AMP be modified as follows:

- Update the AMP to reflect the most recent physical modifications. As required by the March 31, 2006 AMP, the additional Belco filtration modules have been installed.
- Allow alternative flow calculation methodologies (Equation 2) per 40 CFR 63 Subpart UUU (40 CFR § 63.1573 (a) (2)).

EPA approves the following AMP modification for opacity:

This alternative monitoring plan (AMP) is to be implemented in place of the requirement to install and operate a continuous opacity monitoring system (COMS) required by NSPS Subpart J [40 CFR § 60.105(a)(1)] and by reference from MACT Subpart UUU (Table 2).

The ConocoPhillips Fluid Catalytic Cracking Unit (FCCU) Wet Gas Scrubber (WGS) is not a venturi scrubber, so the requirements of Tables 2 and 3 of MACT Subpart UUU apply. Because a WGS is being used and as the result of the presence of condensed water in the stack, a COMS will not accurately measure opacity. An appropriate continuous parameter operating system (CPMS) for the ConocoPhillips FCCU WGS includes monitoring the WGS liquid-to-gas (L/G) ratio and the weight percent solids in the scrubber recirculation liquid. The value for L will be determined by measuring the amperage to each WGS recirculation pump motor that is operating, calculating the power generated by the pump motor at the measured amperage using a standard equation from the Chemical Engineers Handbook, determining the liquid flow rate at the calculated power input from the pump manufacturer's Centrifugal Pump Characteristics

Curve and summing the liquid flow rate from each operating pump. The value for G will be measured by a gas flow meter or calculated in accordance with 40 CFR § 63.1573(a)(2)(iii) using control room instrumentation for air flow into the regenerator, and continuous gas analyzers on the exhaust from the regenerator. As described in the guideline of 40 CFR § 63.1564(b)(2) and (3), the L/G ratio will be calculated and recorded at least once every operating hour. ConocoPhillips has established a minimum L/G ratio of 1.25 calculated on a three-hour block average based on performance testing.

The weight percent solids in the WGS liquid must be sampled and analyzed weekly. ConocoPhillips has established a maximum weight percent value of 1.0 based on data taken during performance testing.

ConocoPhillips has developed and must maintain a written monitoring plan which describes the specific CPMS for this AMP including the measurement equipment, equations, centrifugal pump characteristics curves or algorithms, sampling methods, analytical methods and operation and maintenance requirements. This monitoring plan must be reviewed annually and revised, if necessary, and made available to EPA and NWCAA upon request. This CPMS will meet the requirements of 40 CFR §63.1572(c) and (d).

If you have any questions about this approval, please contact Madonna Narvaez at 206-553-2117, or electronically at narvaez.madonna@epa.gov.

Sincerely,

Nancy Helm, Manager
Federal and Delegated Air Programs Unit

cc: Tim Hall, ConocoPhillips
Annie Naismith, NWCAA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 150
Seattle, WA 98101-3140

AIR & RADIATION
DIVISION

APR 1 7 2019

Mr. John L. Anderson
HSE Manager
Phillips 66, Ferndale Refinery
PO Box 8
Ferndale, Washington 98248

Re: Request for Alternative Monitoring Plan for TRS CEMS at Ferndale Refinery

Dear Mr. Anderson:

This letter is in response to the May 2016 application submitted to the U.S. Environmental Protection Agency (EPA), Region 10 and subsequent information provided on behalf of the Phillips 66 Ferndale Refinery requesting an alternative monitoring plan (AMP) for the calibration of a total reduced sulfur (TRS) continuous emissions monitoring system (CEMS) subject to the requirements of 40 CFR part 60, subpart Ja: *Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification, Commenced after May 14, 2007* (NSPS Ja). The authority to approve alternatives to any monitoring procedures or requirements of 40 CFR part 60 under 40 CFR 63.13(i) is retained by EPA and has not delegated to states in Region 10. After receipt and consideration of your written application and consulting with the Office of Air Quality Planning and Standards (OAQPS), we are conditionally granting your request.

NSPS Ja, at 40 CFR 60.107a(e)(1), requires the installation, operation, calibration, and maintenance of a TRS CEMS according to Performance Specification 5 in appendix B and subject to the applicable quality assurance procedures in appendix F. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare. For a refinery with a sulfur recovery unit or a sulfuric acid plant, nearly pure hydrogen sulfide (H_2S) could be discharged to the flare under upset conditions. NSPS Ja would therefore require daily calibration checks using a span gas with a sulfur concentration several hundred-thousand parts-per-million (ppm), which could represent a safety hazard to refinery personnel.

The May 2016 application provided documentation showing instrumental linearity using sulfur dioxide (SO_2) as the analyte and requested to perform daily drift checks of the TRS CEMS using a low concentration gas (approximately 165 ppm H_2S).

In discussing the 2016 proposal with OAQPS, we determined that a laboratory demonstration showing the type of detector being used is accurate and linear over the full expected range for the species detected and not a surrogate (i.e. H_2S or some other form of reduced sulfur, not SO_2) must be provided. This was provided with in a supplemental December 2018 response.

Because the detector has been demonstrated to be accurate and linear over the full expected detection range, high concentration H_2S is a significant safety hazard to refinery personnel, and this monitoring is performed to detect the threshold for a root cause analysis and not to directly monitor compliance with an emission limit, the EPA is approving the following AMP for the flare TRS CEMS at the Ferndale Refinery without requiring the routine use of high concentration H_2S pursuant to 40 CFR 60.13(i). Phillips 66 may:

1. Perform an initial, seven-day certification over both the low and high range spans of the detector. During the initial certification, the detector shall be challenged by a relative accuracy test audit (RATA) or a cylinder gas audit (CGA) at 20-30 percent and 50-60 percent of the low span and 50-60 percent of the high span. After this, the high span is only challenged during the quarterly CGA. (For an existing CEM that has gone through initial certification, the applicant may provide documentation.)
2. After initial certification, high concentration gases need not be maintained on site routinely. Daily drift checks may consist of zero checks and either mid or high-level checks of the *low span gas only*.
3. Quarterly CGA shall include gases at similar concentrations as those used during the initial certification, as required by NSPS Ja Performance Specification 5 in appendix B and subject to the applicable quality assurance procedures in appendix F.

The AMP shall apply only to certification of the ATOM FGA-1000 model detector used to monitor TRS at the flare system at the Ferndale Refinery. The AMP does not waive annual RATA testing, nor does it have any impact on any other applicable requirements.

If you have any questions about this about this matter, please contact Geoffrey Glass of my staff at (206) 553-1847 or glass.geoffrey@epa.gov.

Sincerely,

Kelly McFadden

Kelly McFadden, Manager
Stationary Source Unit

Cc: Mark Buford, Executive Director, Northwest Clean Air Agency
Toby Mahar, Compliance Manager, NWCAA (email)
Daniel Mahar, Environmental Engineer, NWCAA (email)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

APR 4 2003

Reply To
Attn Of: OAQ-107

Tim Hall, Environmental Coordinator
ConocoPhillips
Ferndale Refinery
3901 Unick Road - P.O. Box 8
Ferndale, Washington 98248

Re: Alternative Sulfur Monitoring Plan
Subpart J Truck Rack Vapor Combustion

Dear Mr. Hall:

EPA received your letter dated February 24, 2003, in which you requested approval of an alternative monitoring plan (AMP) for the NSPS Subpart J monitoring requirements that apply to the John Zinc Thermal Oxidizing Flare at the truck loading rack. This alternative monitoring plan was requested as provided for in 40 CFR § 60.13(i). This letter contained data requested by EPA in support of your original request dated September 11, 2002.

EPA has reviewed the plan that was attached to your February 24, 2003, letter titled "Alternative Monitoring Provisions for Truck Loading Rack." This AMP was evaluated using the guidance published by EPA in a document titled "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas." EPA finds that your AMP is consistent with the guidance in "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas" and that the monitoring data you submitted provides reasonable assurance that the H_2S content in the truck loading rack vapors will be significantly less than the Subpart J requirement of <230 mg/dscm (162 ppmv). Therefore, EPA approves the AMP titled "Alternative Monitoring Provisions for Truck Loading Rack" that was submitted with your letter of February 24, 2003, with the provision that you change one word which appears to be a typographical error. In the first sentence of Section 2.0 (a) of the AMP the word "deep" should be changed to the word "keep."

If you have any questions about this AMP approval, please contact Madonna Narvaez of my staff at (206) 553-2117 or electronically at narvaez.madonna@epa.gov.

Sincerely,

Jeff KenKnight

Jeff KenKnight, Manager
Federal and Delegated Programs Unit

ConocoPhillips

Ferndale Refinery
3901 Unick Road – P.O. Box 8
Ferndale, Washington 98248
phone 360.384.1011

February 24, 2003

Jeff KenKnight, Director
Federal & Delegated Air Program
EPA, Region 10
1200 Sixth Avenue
Seattle, WA 98101

Alternative Sulfur Monitoring Plan
Subpart J Truck Rack Vapor Combustion
File No. 6.2.3.9.2.4

Dear Mr. KenKnight,

The ConocoPhillips Ferndale Refinery operates a truck loading rack, which is subject to 40 CFR 60 Subpart J limitations to sulfur dioxide in the vapor recovered from gasoline cargo tank filling. The John Zinc Thermal Oxidizing Flare (ZTOF), installed to combust these vapors, does not feature a fuel gas sulfur monitoring system that is explicitly compliant with subpart J. On September 11, 2002, ConocoPhillips requested approval of the attached alternative monitoring plan for sulfur dioxide in the truck loading rack vapor combustion unit. On October 22, 2002, EPA requested that ConocoPhillips provide supporting test results from sampling the gas stream using appropriate H_2S monitoring. The tests were performed following the methods outlined in the EPA document *Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas – Conditions for Approval of the Alternative Monitoring Plan for Miscellaneous Refinery Fuel Gas Streams.*

The tests were started on January 8, 2003. Length-of-stain detector tubes in the range of 0-10/0-100 ppm (N=10/1) were used for testing. Seven samples were collected from the infrequently operated gas stream. Due to irregular loading schedules and other activities in the area, the grab samples could not be taken on consecutive days. To ensure that the tests were representative, samples were taken from the gas stream just before it entered the ZTOF. The sampling was completed on February 24, 2003. The following table summarizes the H_2S test results

OFFPLOT TRUCK RACK
Gasoline Vapor Combustion System (ZTOF)

Date	Time	Product	H2S (ppm)	Drager 10 strokes
1/8/03	0815	RegUnl	1	yes
1/9/03	1030	RegUnl	0	yes
1/10/03	1500	RegUnl	0	yes
2/14/03	0900	RegUnl	0	yes
2/18/03	0800	Reg/SUL	0	yes
2/21/03	0900	RegUnl	0	yes
2/24/03	0730	RegUnl	0	yes

The test results are representative of typical operating conditions affecting H_2S content in the gas stream going to the loading rack ZTOF. Sample range and variability calculations were not performed because all test values were essentially zero and obviously well below the acceptability limit of 81 ppm (one-half the maximum allowable fuel gas standard of 162 ppm under Subpart J).

If you require additional information, please contact me at (360) 384-8424.

Sincerely,

T. J. Hall
Environmental Specialist

Alternative Monitoring Provisions for Truck Loading Rack

The ConocoPhillilps Ferndale Refinery shall comply with the requirements of 40 CFR 60 Subpart J except as explicitly listed below. The following alternate monitoring plan shall only apply to the truck loading rack Zink Thermal Oxidation Flare (ZTOF) as long as all fuels loaded at the truck loading rack meet the specific sulfur product specification noted in Attachment 1. Pilot and assist gas shall be commercial grade propane gas purchased from an independent distributor.

1.0 Monitoring methods

(a) ConocoPhillips Ferndale Refinery shall monitor all fuels loaded at the truck loading rack to assure that they meet the specific sulfur product specification for that finished product.

2.0 Record Keeping Requirements

(a) ConocoPhillips Ferndale Refinery shall keep a record of each fuel sampling performed pursuant to Section 1.0 Each record shall identify the date and location of sampling.

(b) ConocoPhillips Ferndale Refinery shall maintain records for a period of five (5) years after the generation of such documentation. This alternative monitoring plan shall be kept permanently, or until it has been replaced with a different alternative monitoring plan or the truck loading rack is permanently taken out of service.

3.0 Reporting Requirements

(a) Within 30 days of the change, ConocoPhillips Ferndale Refinery shall report any change in the type of fuels or change in the sulfur product specification of the fuels loaded at the truck loading rack if the sulfur product specification has a higher sulfur content than shown in Attachment 1.

(b) Within 30 days of the change, ConocoPhillips Ferndale Refinery shall report any change in the type of gases used as pilot or assist gas at the truck loading rack ZTOF.

Attachment 1

Type of Fuel Loaded	Sulfur Product Specification (Total Sulfur Concentration)
Regular Unleaded Gasoline	0.1 % (weight)
Super Unleaded Gasoline	0.1 % (weight)
Midgrade Unleaded Gasoline	0.1 % (weight)
Diesel	0.047 % (weight)
Ultra Low Sulfur Diesel	30 ppm (weight)