# Statement of Basis for the Air Operating Permit - Final *#014R2*

## **Shell Puget Sound Refinery**

Anacortes, Washington

**September 14, 2021**

northwest Clean Air agency

*Serving Island, Skagit & Whatcom Counties*

# PERMIT INFORMATION

## Equilon Enterprises LLC

## dba Shell Oil Products US Puget Sound Refinery

## 8505 South Texas Road, Anacortes, Washington

SIC: 2911
NAICS: 324110

NWCAA ID: 1005-V-S

**Corporate Responsible Official**

John White
General Manager
PO Box 622
Anacortes, WA 98221
(360) 293-1701

**Corporate Inspection Contact**

Tim Figgie
Sr. Staff Engineer
PO Box 622
Anacortes, WA 98221
(360) 293-1525

**Northwest Clean Air Agency**

1600 South Second Street
Mount Vernon, Washington 98273-5202
(360) 428-1617

**Prepared by:**

Crystal Rau
Air Quality Scientist
(360) 419-6771

| Air Operating Permit Number: | Issuance Date: |
|---|---|
| 014R2 | September 14, 2021 |
| Renewal Application Due: | Expiration Date: |
| September 14, 2025 | September 14, 2026 |

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# 1. INTRODUCTION AND GENERAL FACILITY DESCRIPTION

Puget Sound Refinery (PSR), owned by Equilon Enterprises LLC dba Shell Oil Products US, and as of May 4, 2021, under agreement to be sold during the fourth quarter of 2021 to HollyFrontier Corporation, is required to obtain an air operating permit (AOP or Permit) because it has the potential to emit all of the following:

- 100 tons or more of oxides of nitrogen ($NO_X$), sulfur dioxide ($SO_2$), particulate matter, volatile organic compounds (VOC), and carbon monoxide (CO);
- 10 tons per year or more of any hazardous air pollutant (HAPs);
- 25 tons per year or more of a combination of HAPs; and
- Both 100,000 tons $CO_2$e per year and 100 tons greenhouse gases (GHGs) per year.

The purpose of this Statement of Basis (SofB) is to set forth the legal and factual basis for the conditions of the Air Operating Permit (AOP). This document also provides background information to facilitate review of the permit by interested parties. The Statement of Basis is not a legally enforceable document in accordance with WAC 173-401-700(8).

The Northwest Clean Air Agency (NWCAA or Agency) issued the original AOP #014 on November 26, 2002. The expiration date was November 25, 2007. The AOP was modified and re-issued as AOP #014M1 on September 24, 2004, mid-permit term. The AOP was renewed as AOP #014R1 on November 5, 2014. The expiration date was November 5, 2019. On May 5, 2015, an administrative amendment was issued as AOP #014R1M1.

PSR submitted a timely application for the 2nd renewal on November 5, 2018 which was determined complete on January 2, 2019. Changes made to the AOP during this 2nd renewal are listed in SofB Section 1.2. See SofB Appendix A for changes made to previous permits.

## 1.1 Facility Description

The facility produces petroleum-based fuels as classified under the Standard Industrial Classification code 2911. It is located on March Point, a heavy industrial area near Anacortes, Washington. The refinery was originally built by Texaco, Inc. and began operation in 1958. Texaco owned and operated the facility until Texaco formed an alliance with Shell Oil Company on January 1, 1998. The resulting company was Equilon Enterprises LLC (Equilon). In April of 2002, Shell purchased Texaco's interest in Equilon. As such, PSR is now owned by Equilon Enterprises LLC dba Shell Oil Products US. On May 4, 2021, Equilon Enterprises announced that they had reached an agreement for the sale of Puget Sound Refinery with HollyFrontier Corporation, set for the fourth quarter of 2021. As such, it is expected that during the upcoming term of this renewed permit, ownership of the refinery will change, however, the requirements contained in the permit will apply regardless of which corporate entity retains ownership of the refinery.

A cogeneration facility is also part of the Puget Sound Refinery site. The cogeneration facility was originally owned by the March Point Cogeneration Company (MPCC); Shell PSR took possession of the facility in February 2010.

Air Liquide and Matheson (formerly Linde) operate hydrogen plants on property owned by Shell PSR and adjacent to the refinery. However, both Air Liquide and Matheson are independent companies and are permitted separately from PSR. Both Air Liquide and Matheson are required to obtain Title V air operating permits.

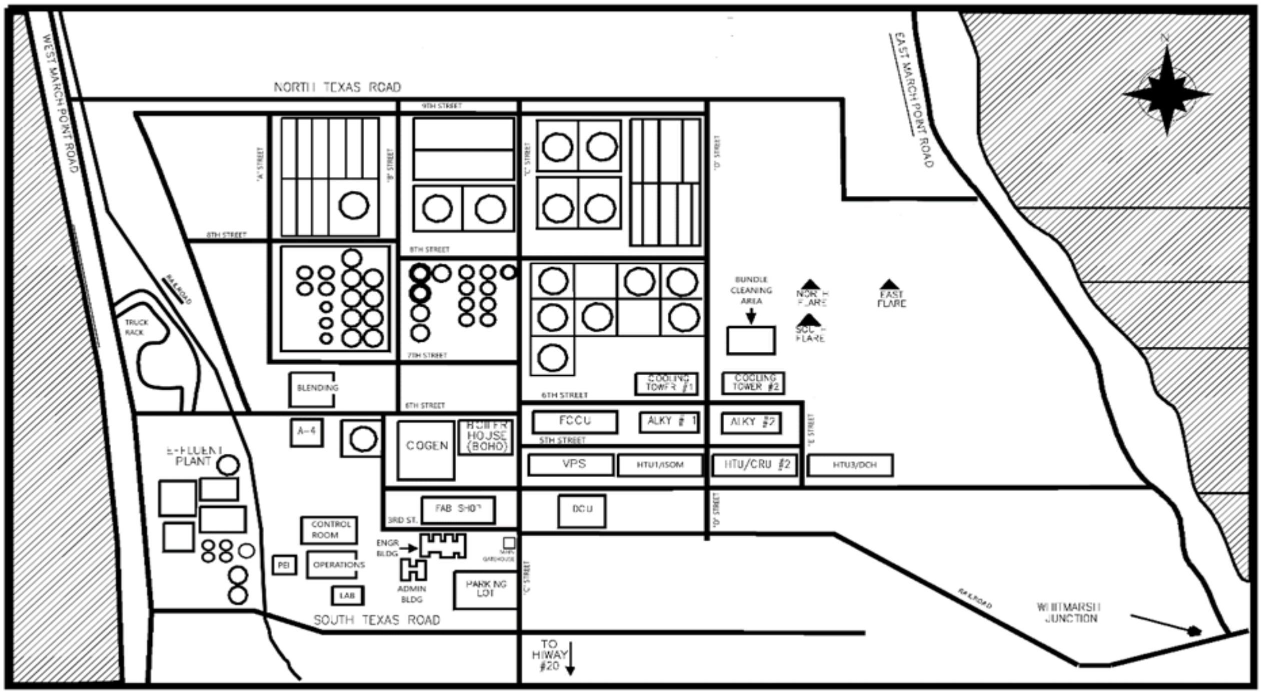


**Figure 1 Refinery Plot Diagram**

Figure 1 shows the layout of the process unit areas, storage tanks and the refinery's orientation to local roadways. A complete list of acronyms used to identify refinery processes and units can be found in Section 4.4, near the end of this document.

PSR is located between Highway 20 to the south and the Marathon refinery to the north. Figure 2 is an aerial view of the refinery.

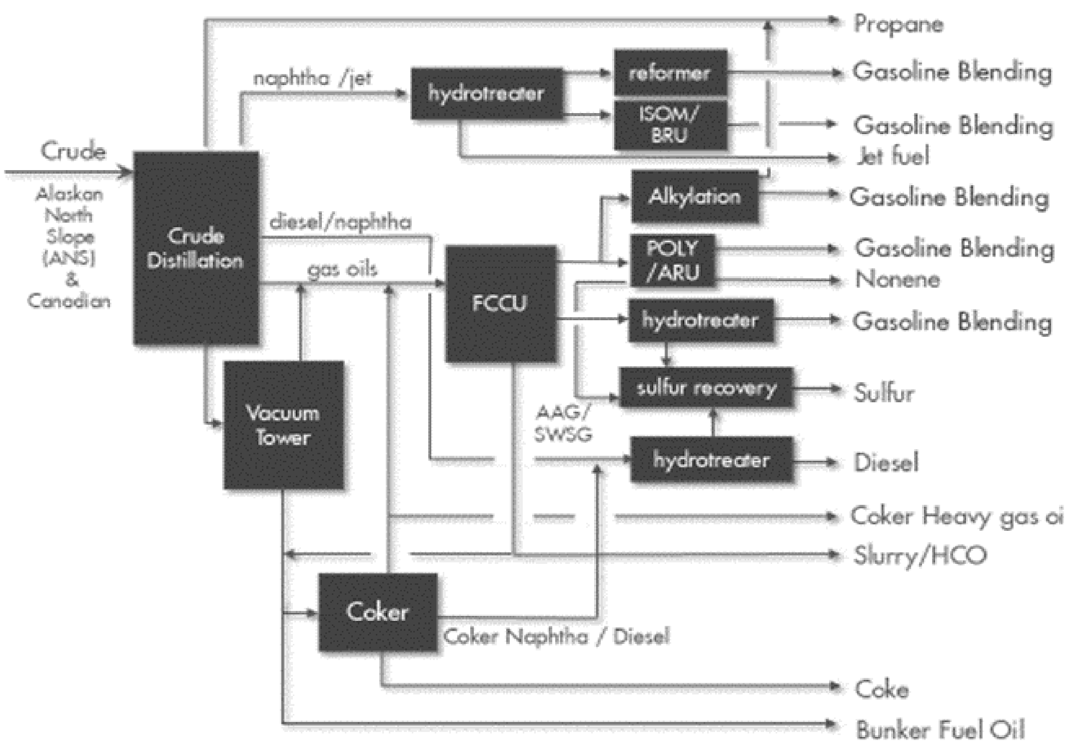
**Figure 2 Aerial View of the Refinery**

The PSR refinery has an annual average crude processing rate of approximately 150,000 barrels per day. Refining crude oil produces petroleum products, including gases, gasoline, distillate fuels, fuel oils, and petroleum coke. Processing will utilize any or all of the following four basic processes: distillation, conversion (including cracking, reforming and polymerization), purification to remove contaminants, and blending. There are ancillary structures for storage, maintenance, steam generation, and administrative activities.

The refining process generates usable byproducts along with waste streams, both hazardous and non-hazardous. PSR operates a wastewater treatment facility that treats refinery wastewater and discharges the treated water into Fidalgo Bay. Both hazardous and non-hazardous materials are shipped off-site to appropriate waste disposal facilities. Elemental sulfur is generated during the removal of sulfur from hydrocarbon streams to produce low sulfur fuels and blending products. Elemental sulfur is a usable byproduct that is shipped off-site to companies that use the elemental sulfur as a feedstock.

PSR is organized into major processing areas. Each processing area is described in more detail in the body of the Statement of Basis. Air emissions at PSR are generated primarily as a result of products of combustion in heaters/boilers and from fugitive emissions from leaking process equipment or from storage tank and product transfer losses.

PSR processes primarily Alaskan North Slope (ANS) and various Canadian crude oils, but may also run small amounts of other crude oils purchased on the spot market. At PSR, the main steps in processing include separation by distillation and downstream conversion by cracking, reforming and combination. Figure 3 shows a simplified process flow diagram of PSR's refining process. PSR utilizes Catalytic Reformer Units (CRUs), Hydrotreater Units (HTUs), Alkylation (ALKYs) and Sulfur Recovery Units (SRUs) to provide operational flexibility.




## Figure 3 Process Flow Diagram

The PSR facility began operation in 1958. The major projects completed since original construction include:

- 1976 Octane Improvement Project consisting of the installation of CO Boiler (COB) 2, the Catalytic Polymerization Unit (CPU), HTU2, CRU2, Alky2, Cooling Tower 2, and an expansion of the Crude processing unit
- 1981 installation of the Sulfur Recovery Unit (SRU)
- 1983 installation of the Delayed Coking Unit (DCU)
- 1990/91 installation of EP controls
- 1998 FCCU Vertical Riser Project/CPU Expansion/Vacuum Resid Uplift
- 1999 SRU expansion
- 2003 installation of HTU3 to meet low sulfur gasoline requirements
- 2003 construction of a new Sulfur Recovery Unit (SRU4)
- 2004 modification of HTU2 to facilitate the production of ultra low sulfur diesel
- 2005 installation of a new wet gas scrubber (WGS) to control PM and $SO_2$ from the FCCU/CO Boilers
- 2006 installation of flare gas recovery unit (FGR)
- 2010 Shell purchased MPCC
- 2011 construction of the Benzene Reduction Project to meet the gasoline benzene standards
- 2013 shutdown of CRU1 heaters
- 2014 PSR Feedstock Import project for rail unloading of intermediate feedstocks for further processing in the FCCU and DCU
- 2016 Modifications for VPS Process Improvement Project to upgrade the unit to increase operational reliability and flexibility
- 2018 modification of HTU3 for Tier III Product Changes to meet the EPA Tier III low sulfur gasoline specifications
- 2018 construction of a new crude storage tank
- 2018 modification of PSR Feedstock Import project to allow receipt of lighter crudes for processing in the VPS, as well as diesel and gas oil for processing in the hydrotreaters
- 2019 construction of new gasoline and diesel storage tanks

Numerous other smaller projects have been completed at PSR and are identified within the associated process area descriptions in this Statement of Basis. Note that no Prevention of Significant Deterioration (PSD) permits have been issued to PSR.

Table 1-1 is a list of the Orders of Approval to Construct (OACs), Regulatory Orders (ROs), and Compliance Orders (COs) included in the AOP. Any updates to the provisions of these Orders have been incorporated into the AOP renewal, except as discussed in the individual process unit sections. The OAC numbers marked with asterisks in Table 1-1 are applicable to the listed equipment but have no ongoing requirements. As such, they are listed in AOP Section 1 marked with asterisks but are not included in AOP Section 5. Additional information on individual OACs is included in SofB Section 3.

**Table 1-1: Active OACs, ROs, and COs**

| Permit Issuance Date | OAC | Description | Startup Date | Super-sedes |
|---|---|---|---|---|
| April 10, 2013 | 241a | Storage Tank - Tank 70 - OAC cleanup | existing | 241 |
| April 10, 2013 | 262a* | Storage Tank - Tank 15 - OAC cleanup | existing | 262 |
| April 10, 2013 | 286b | Hydrotreater 1 - OAC cleanup | existing | 286 & 286a |
| April 10, 2013 | 295a* | Storage Tank - Tank 38 - OAC cleanup | existing | 295 |
| April 12, 2013 | 296a | Nonene Unit – Included QQQ, OAC cleanup | existing | 296 |
| April 10, 2013 | 297a | Storage Tank - Tank 45 – Remove NSPS Kb as inapplicable, OAC cleanup | existing | 297 |
| April 10, 2013 | 316a* | Storage Tank - Tank 71 - OAC cleanup | existing | 316 |
| April 12, 2013 | 337a | Storage Tank - Tank 39 - OAC cleanup | existing | 337 |
| April 10, 2013 | 341a | Storage Tank - Tank 60 - OAC cleanup | existing | 341 |
| April 10, 2013 | 345a* | Storage Tanks - Tanks 72, 73, 74 – OAC cleanup | existing | 345 |
| April 10, 2013 | 380c | Truck Rack - OAC cleanup | existing | 380b |
| June 13, 2018 | 475i | Cogens 1 & 2 – Remove fuel oil-firing capability | existing | 475h |
| June 13, 2018 | 476h | Cogen 3 – Remove fuel oil-firing capability | existing | 476g |
| April 10, 2013 | 514a* | EP controls - OAC 332, 416, 417, & 514 combined and clean up | existing | 514 |
| January 30, 2014 | 623f | FCCU - Cleanup and extract out Equilon Consent Decree requirements | existing | 623e |
| April 10, 2013 | 628d | DCU heater 15F-100 - Remove MMBtu/hr emission limit and incorporated limit averaging periods | existing | 628c |
| January 30, 2014 | 630c | HTU2 ULSD – OAC cleanup, add ongoing compliance demonstration, clarify LDAR requirements | existing | 630b |
| May 3, 2010 | 684b | VPS Heater 1A-F8 - Clarify testing requirements | existing | 684a |
| March 20, 2009 | 757a | Diesel Railcar Loading – OAC cleanup | existing | 757 |
| March 20, 2009 | 772b | Butadiene – OAC cleanup | existing | 772a |
| December 8, 2017 | 787f | HTU3 – modification to install new CDHDS burners | -- | 787e |
| May 15, 2018 | 787g | HTU3 – correct effective date | November 7, 2019 | 787f |
| May 5, 2021 | 787h | HTU3 – correct VE method | -- | 787g |
| February 27, 2002 | 797 | Wharf Generator | existing | -- |
| September 4, 2018 | 828b | SRP – Calculation of SO2 limit based on oxygen enrichment | January 30, 2019 | 828a |

| Permit Issuance Date | OAC | Description | Startup Date | Super-sedes |
|---|---|---|---|---|
| January 30, 2014 | 883b | Isomerization Unit – Clarify LDAR requirements | January 19, 2006 | 883 |
| January 30, 2014 | 887a | Alky1 spare flare drum pump – Clarify LDAR requirements | September 22, 2005 | 887 |
| January 30, 2014 | 918b | Flare gas recovery – Clarify LDAR requirements | June 27, 2006 | 918a |
| April 12, 2013 | 919a | VPS Heater 1A-F5 & 1A-F6 - OAC cleanup | September 2000 | 919 |
| April 12, 2013 | 929b | VPS Heater 1A-F4 - OAC cleanup | January 2006 | 929a, RO20, RO20a |
| July 22, 2009 | 1045* | Benzene Reduction Project | April 5, 2011 | -- |
| July 22, 2009 | 1046 | Ethanol Unloading & Storage Project | July 6, 2010 | -- |
| April 12, 2013 | RO14a | Coke Transport - RO Cleanup | -- | RO14 |
| April 10, 2013 | CO 07 | Memorialize NSPS J applicability to heaters & boilers from Equilon Consent Decree | -- | -- |
| April 29, 2013 | CO 08 | Tank 38 - Memorialize slotted guidepole requirement from Slotted Guidepole' Emission Reduction Program agreement | -- | -- |
| February 12, 2014 | CO 10 | FCCU – Memorialize Equilon Consent Decree requirements | -- | -- |
| July 11, 2018 | 1181a | PSR Feedstocks Import (PFI) project – Allow receipt of lighter feedstock | November 29, 2018 | 1181 |
| July 30, 2015 | 1215 | New Laboratory | February 15, 2017 | -- |
| May 5, 2016 | | Consent Decree Terminated | | |
| October 21, 2016 | 1253 | VPS Process Improvement (PI) Project | December 4, 2018 | -- |
| June 7, 2018 | 1291 | Crude Storage Tank (TK503) | September 25, 2020 | -- |
| July 1, 2019 | 1301 | Gasoline and Diesel Storage Tanks (TK504 & TK 5050) | not completed yet | -- |

## 1.2 Permit Revisions during Second Renewal

The NWCAA received the application for the second AOP renewal on November 5, 2018. The following revisions have been made to the permit during this renewal.

- Removed any further reference to the Equilon Consent Decree from the AOP. The Equilon Consent Decree was terminated May 5, 2016. References to both the Heater and Boiler Consent Decree and Equilon Consent Decree have been left in the SofB for historical purposes only.
- Updated the source contact information and general permit information on the permit information page.

**Changes to Section 1 of AOP**

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

Updated Section 1 Tables, as follows:

- Added Pressure Relief Devices that release to atmosphere – in 1.1 VPS, 1.3 FCCU & 1.7.1HTU1
- Added Coke Drum Vents in 1.2 DCU
- Removed Heaters (6D-F2, -F3 & -F4), Feed Surge Drum Vent & 4 Heat Exchangers in HAP service at 1.5.1 CRU1. Moved 1 Heat Exchanger to 1.7.4 ISOM unit.
- Updated 1.7.3 HTU3 to reflect modification date associated with OAC 787h.
- Added Heat Exchanger (6D-E3) in HAP service from CRU1 to 1.7.4 ISOM unit.
- Removed reference to Process Drains at 1.8 SRU – no subject drains at unit.
- Removed diesel backup fuel reference for all three Cogeneration units and Duct Burners based on updated OAC 475i & OAC 476h in 1.9 Utilities
- Removed reference to Process Drains at 1.10.4 Ethanol Unloading & Storage – no subject drains at unit.
- Added 1.10.6 PSR Feedstocks Import (PFI) table to list 7 Double-sided Railcar Unloading Station to Tankage & Process Drains approved in OAC 1181a.
- Added Process Drains to the list of equipment listed in 1.13.1 Effluent Plant & Sewer System
- Added Tanks 503 & 505, approved in OAC 1291 and 1301, respectively, to 1.14.1 EFR Tanks.
- Added Tank 504, approved in OAC 1301, to 1.14.3 Fixed Roof Tanks.
- Added 1.15 Refinery Support Operations, which lists Refinery Laboratory approved in OAC 1215, Spray Coating Operations & Gasoline Dispensing.

Revised AOP Sections 2 to be consistent with current NWCAA format and content. Updated introductory text, citations and dates.

**Changes to Section 3 of AOP**

In Section 3, updated introductory text 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.

<u>40 CFR 60 NSPS</u>

- 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

<u>40 CFR 61 NESHAP</u>

- Updated 3.2.8 Emission Tests language

<u>40 CFR 63 NESHAP</u>

- 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 OMMP requirements because these requirements are now specifically cited in the requirement tables specific to the applicable affected sources (FCCU, CRU, SRU).
- Removed 3.3.4 SSMP requirements as there are no subject NESHAP sources that still require SSMP plans. This includes removal of affirmative defense provisions in 3.3.4.4.
- Renumbered conditions.
- 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 3.3.21 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

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 & 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.

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

4.28 & 4.29 - 40 CFR 63 Subpart CC (Refinery MACT 1)

- Requirement that emission standards apply to affected sources at all times
- General Duty to Minimize Emissions

4.30, 4.31. & 4.32 - 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

4.33 & 4.34 - 40 CFR 63 Subpart ZZZZ (RICE MACT)

- General Duty to Minimize Emissions

4.36, 4.37, 4.38 & 4.39 - 40 CFR 63 Subpart CC Fenceline Benzene Monitoring

- Sampling requirements
- Met station requirements
- RCA & Initial CAA requirements
- Corrective Action plan requirements

4.40 – 40 CFR 63 Subpart CC Maintenance vents requirements

### Changes to Section 5 of AOP

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 & 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.

- Added new sections - 5.10.7 for PSR Feedstock Imports and 5.15 Refinery Support Operations.
- Added 5.1.20 – OAC 1253 Condition 1 BACT for Equipment Leaks.
- Added 5.1.21, 22 & 23 – VPS Atmospheric Tower Atmospheric PRD
    - Organic HAP Gas & Vapor Service – Operating & Pressure Release Requirements
    - Organic HAP – Pressure Release Management
    - Organic HAP – RCA & CAA
- Added 5.2.7 Existing DCU Coke Drum Vent Depresssurizing
- Removed reference to "complying upon completion of 2014 turnaround" in 5.3.1. at FCCU as has already occurred.
- For 5.3.3, added alternate work practice for FCCU catalyst regenerator for organic HAP during periods of startup, shutdown & hot standby and associated MR&R.
- For 5.3.9, 10 & 11 – FCCU PM and VE, added lower visible emission limit to the operating visible emission limit. Added alternate work practice for FCCU catalyst regenerator for metal HAP during periods of startup, shutdown & hot standby and associated MR&R.
- For 5.3.15 - added alternate work practice for FCCU catalyst regenerator for metal HAP during periods of startup, shutdown & hot standby and associated MR&R. Added performance test requirements.
- Added 5.3.16 – OMMP for FCCU and associated MR&R.
- Added 5.3.25, 26 & 27 – FCCU Main Fractionator Atmospheric PRD
    - Organic HAP Gas & Vapor Service – Operating & Pressure Release Requirements
    - Organic HAP – Pressure Release Management
    - Organic HAP – RCA & CAA
- Deleted 5.5.1, 2, 3, 4, 5, 6, 7, 8, & 9 – CRU1 Heaters, Feed Surge Drum Vent, 4 of 5 Heat Exchangers have been shutdown. Remaining Heat Exchanger now serves ISOM unit and requirements for it are listed in 5.7.4.
- Updated 5.5.8 – CRU2 Catalyst Regeneration for Organic HAP – control by venting to flare meeting requirements under 63.670 and associated MR&R.
- Updated 5.5.9 – cited requirements for CRU2 Catalyst Regeneration for Inorganic HAP
- Added 5.5.10 – OMMP requirement for CRU and associated MR&R.
- Added 5.7.6, 7, & 8 – HTU1 Fractionator Atmospheric PRD
    - Organic HAP Gas & Vapor Service – Operating & Pressure Release Requirements
    - Organic HAP – Pressure Release Management
    - Organic HAP – RCA & CAA
- Updated 5.7.21, 22, 23, 25 & 30 – HTU3 to reflect changes resulting from modified OAC 787h.
- Added 5.7.32 – Heat Exchanger in HAP service (6D-E3) serving ISOM unit, instead of CRU1.
- Updated 5.8.1, 2, 3, 4, 6, 7, 9 & 10 – SRUs to reference OAC 828b with correct date.
- Revised 5.8.7 – SRU $SO_2$ & HAP Emissions to allow for calculation of emission limit based on oxygen enrichment using equation 1, as permitted in OAC 828b Condition 3 and 40 CFR 60 Subpart J/Ja, along with associated MR&R. Added alternate work practice standards for HAP emissions during periods of startup & shutdown and associated MR&R.
- Added 5.8.8 – OMMP requirement for SRUs and associated MR&R.

- Updated 5.9.4, 5, 8, 9, 10 &13 Combustion Turbine Units 1 & 2 – modified OAC 475i with reissue date for removal of permission to burn distillate fuel (including avjet). Removed: distillate and avjet monthly fuel reporting; NOx and $SO_2$ emission limitations when combusting distillate and avjet; sulfur content of fuel limitation; and VE observation when burning liquid fuels.
- Updated 5.9.14, 15, 18, 19, 20 & 23 (previous permit was 5.9.24) Combustion Turbine Unit 3 - modified OAC 476g with reissue date for removal of permission to burn distillate fuel (including avjet). Removed: distillate and avjet monthly fuel reporting; NOx and $SO_2$ emission limitations when combusting distillate and avjet; sulfur content of fuel limitation; PM emission limit with associated source test requirement; and VE observation when burning liquid fuels.
- Removed 5.9.23 – PM emission limit with associated source test requirement – no longer allowed to combust distillate or avjet.
- Added Section 5.10.7 for PSR Feedstock Imports, included OAC 1181a requirements.
- Replaced and renumbered flare requirements to include requirement & associated MR&R for flares from 40 CFR 63 Subpart CC, 63.670 & 63.671, including:
  - Flare Pilot Flame
  - VE (< flare smokeless design capacity)
  - Flare Tip Velocity (< flare smokeless design capacity)
  - Emergency Flaring (> flare smokeless design capacity)
  - Emergency Flaring RCE & CAA (> flare smokeless design capacity)
  - Flare Net Heating Value, Combustion Zone
  - FMP
  - CPMS Monitoring Plan
- For 5.11.10, removed reference to compliance date, as it has already passed.
- For 5.11.11, added reporting requirements.
- For Sections 5.13.2 and 5.13.3 – Effluent Plant EFR Group 1 Wastewater Tanks & IFR Group 1 Wastewater Tanks, requirement tables were condensed, where possible.
- For section 5.14 – Storage Tanks/Vessels, the requirement tables were rebuilt (NEW) as these Tanks were now meeting requirements under 40 CFR 63 Subpart CC, 63.660 which requires compliance with 40 CFR 63 Subpart WW Tanks – Control Level 2, associated NWCAA regulations and any applicable NWCAA issued regulatory orders (OAC, CO). These tanks were split into 3 subgroups 5.14.1 covers the requirements for external floating roof Group 1 tanks, 5.14.2 covers the requirements for external floating roof Group 2 tanks, 5.14.3 covers the requirements for internal floating roof Group 1 tanks, 5.14.4 covers the requirements for internal floating roof Group 2 tanks, and 5.14.5 covers the requirements for fixed roof Group 2 tanks.
- Miscellaneous Tank Farm Requirements was renumbered section 5.14.6.
- Added Section 5.15 Refinery Support Operations. Included:
  - Refinery Laboratory with requirements from OAC 1215 and 40 CFR 60 Subpart QQQ
  - Spray Coating Operations with requirements from NWCAA 508
  - Gasoline Dispensing with requirements from NWCAA 580.6

#### Changes to Section 6 of AOP

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.
- Updated references in 6.2.10 and 6.3.10 to refer to 40 CFR 63 Subpart CC 63.648, updated requirements for flares used as control devices to comply with requirements of 63.670.
- Updated 6.5.1 to remove initial tune-up requirement and initial Notification of Compliance Status. Incorporated additional Boiler MACT language.
- Updated 6.5.2 to remove initial tune-up requirement and initial Notification of Compliance Status. Incorporated additional Boiler MACT language.
- Removed 6.5.3 – Boiler MACT one-time energy assessment has already been completed.
- Removed 6.5.4 – Boiler MACT startup and shutdown MR&R, not required for units designed to burn gas 1 fuels.
- Added 6.5.3 – Boiler MACT General Duty to Minimize Emissions.

**Changes Made to Draft/Proposed AOP and Statement of Basis Prior to Finalizing**

The following clarifications and corrections were made in the Draft/Proposed AOP prior to finalizing the permit documents:

- MR&R for AOP Term 5.13.14 was changed as follows: "Keep records of periods when the ~~tank~~roof is resting on the leg supports."
- MR&R for AOP Term 5.14.16 was changed as follows: "Comply with MR&R under AOP Term 5.14.15~~12~~."
- MR&R for AOP Term 5.14.18 was changed as follows: "Comply with MR&R under AOP Term 5.14.17~~14~~."

Table 1-2 found under Section 1.3 Enforcement History was updated to reflect a $60,000 penalty paid as part of resolution of NOV 4459 (the draft/proposed SofB noted that each violation listed in the table had been resolved except NOV 4459).

Table 1-3 found under Section 1.5 Emission Inventory was updated to reflect that GHG emissions were reported for the Cogeneration Units (only) and in units of metric tons.

## 1.3 Enforcement History

A summary of Notices of Violation (NOVs) issued to the refinery by the NWCAA from November 2013 through March 31, 2021 is presented in Table 1-2. Each violation listed in the table has been resolved through a combination of penalty assessments and by corrective action taken by the source.

**Table 1-2: Notice of Violations Issued to PSR**

| Case No | Violation Date | Issue Date | Description |
|---|---|---|---|
| 4169 | 9/26/12 | 6/29/16 | Failure to implement timely and appropriate repairs to the east flare resulting in an increase in annual emissions of all reported pollutants. Penalty paid $188,869. |

| Case No | Violation Date | Issue Date | Description |
|---|---|---|---|
| 4078 | 5/13/13 | 3/20/14 | Emissions from flare exceeded 1,000 ppmvd $SO_2$ corrected to 7% $O_2$, 60-minute average; fuel gas sulfur content exceeded 162 ppmvd $H_2S$, 3-hr rolling average at hydrotreater (HTU) 2 and HTU3; fuel gas sulfur content exceeded 50 ppmvd $H_2S$, 24-hour rolling average at VPS Heater 1A-F8. Emissions estimated at 102 lb of $SO_2$ resulted from this event. Penalty paid $16,000. |
| 4076 | 6/7/13 | 3/20/14 | Emissions from sulfur recovery unit (SRU) 3 exceeded 250 ppmvd $SO_2$ corrected to 0% $O_2$, 12-hour rolling average; sulfur content of the gas combusted in the flare exceeded 162 ppmv $H_2S$, 3-hour average. Emissions estimated at 846 lb of $SO_2$ resulted from this event. Penalty paid $14,000. |
| 4102 | 7/11/13 | 8/28/14 | Effluent plant outfall pump 9QG68 operated 5 hours as a non-emergency engine and did not meet the the applicable standards for non-emergency engines. Emissions estimated at 5.6 lb of CO resulted from this event. Penalty paid $4,000. |
| 4075 | 11/13/13 | 3/20/14 | Emissions from sulfur recovery unit (SRU) 4 exceeded 1,000 ppmvd $SO_2$ corrected to 7% $O_2$, 60-minute average; 250 ppmvd $SO_2$ corrected to 0% $O_2$, 12-hour rolling average. Emissions estimated at 5.4 tons of $SO_2$ resulted from this event. Penalty paid $15,800. |
| 4094 | 2/6/14 | 6/10/14 | Emissions from the flare exceeded 1,000 ppmvd $SO_2$ corrected to 7% $O_2$, 60-minute average; flare gas sulfur content exceeded 162 ppmvd $H_2S$, 3-hour rolling average; Gas turbine generator 2 exceeded 1-hour CO limit. Emissions estimated at 3,145 lb $SO_2$ and 1 lb CO resulted from these events. Penalty paid $4,000. |
| 4081 | 3/4/14 | 7/22/14 | Emissions from the flare exceeded 1,000 ppmvd $SO_2$ corrected to 7% $O_2$, 60-minute average on 12/19/12; the sulfur content of the gas combusted at the flare exceeded 162 ppmvd $H_2S$, 3-hour rolling average on 3/24/13; the sulfur content of the gas combusted at hydrotreater unit (HTU) 2 fuel mix drum exceeded 162 ppmvd $H_2S$, 3-hour rolling average on 1/9/14; the sulfur content of gas combusted in the flare exceeded 162 ppmvd $H_2S$, 3-hour rolling average on 3/4/14. Emissions estimated at 564.8 lb $SO_2$; 532.4 lb $SO_2$; 2.5 lb $SO_2$; 30 lb $SO_2$ respectively resulted from these events. Penalty paid $21,000. |
| 4120 | 4/6/14 | 12/15/14 | Internal floating roof on Tank 30 landed on its legs and was no longer floating for a period of 8 hours. Emission estimated at 398 lb VOC resulted from this event. Penalty paid $4,000. |
| 4097 | 4/30/14 | 7/10/14 | Emissions from the flare exceeded 162 ppmvd $H_2S$, 3-hour rolling average. Emissions estimated at 1,254 lb $SO_2$ resulted from this event. Penalty paid $4,000. |
| 4171 | 7/30/14 | 9/8/15 | Testing of hydrotreater unit (HTU) 2 was not performed within 180 days of issuance of OAC 630c. Penalty paid $4,000. |
| 4179 | 2/20/15 | 4/8/16 | Uncombusted odorous and toxic compounds were released from the flare during turnaround decontamination activities, causing wide-spread odor nuisance impacts in neighboring communities. Penalty paid $133,000. |
| 4207 | 4/14/16 | 7/18/16 | Gases combusted in the flare exceeded 162 ppm $H_2S$, 3-hour rolling average. Emissions from the flare exceeded 1,000 ppm $SO_2$ corrected to 7% $O_2$, 1-hour average; Emissions from the sulfur recovery unit (SRU) 4 exceeded 1,000 ppm $SO_2$ corrected to 7% $O_2$, 1-hour rolling average. Emissions estimated at 13,400 lb $SO_2$ resulted from this event. Penalty paid $39,400. |

| Case No | Violation Date | Issue Date | Description |
|---|---|---|---|
| 4239 | 11/12/16 | 3/7/17 | CEMs calibrations not performed due to running out of calibration gas, resulting in 56.7 hours of avoidable monitor downtime. Later, the same analyzer was inundated with water when the flare line was steamed out for cleaning and sample cooler could not keep up, resulting in an additional monitor downtime, causing the monthly monitor availability to less than 90% for the operating hours that month. No penalty assessed, corrective action required. |
| 4394 | 7/19/19 | 10/22/19 | Failure to maintain Tank 36 internal floating roof in good operating condition, resting on the stored liquid surface. Emissions estimated at 15 tons of VOC resulted from this event. Penalty paid $49,000. |
| 4420 | Multiple days in 2020 | 7/28/20 | Internal floating roofs on Tanks 30 (4/9/20) and 36 (3/1/20) landed on their legs and were no longer floating for ~ 15 minutes, each; emissions estimated at 16 lbs VOC and 150 lbs VOC, respectively. CEMs calibration drift checks were not performed on 25 consecutive days in April 2020, when electronics malfunction within the HTU2 fuel gas $H_2S$ analyzer; no resulting excess emissions. CEMs downtime at Cogeneration Unit #1 $NH_3$ and $SO_2$ in February 2020, and HTU2 fuel gas $H_2S$ analyzer in April 2020, resulted in less than 90% data availability; no resulting excess emissions. Penalty paid $26,000. |
| 4459 | 8/19/20 & 9/29/20 | 3/25/21 | Visible emissions more than 5 minutes in any 2 consecutive hours (North flare - 8/19/20 & North & South flare - 9/29/20), not meeting minimum net heating value in flare combustion zone (North flare – 9/29/20) and odors during flaring event (9/29/20). Penalty Paid $60,000. |

### 1.4 Periodic Reports

PSR has periodic reporting requirements contained in various orders and regulations. Reported elements provide a valuable tool indicating the refinery's compliance status with regard to an applicable emission limit or operational limit. In addition to these periodic reports the refinery has specific action-based notifications and on-site recordkeeping requirements. Note that, similar to all recordkeeping, the data supporting the reported information must be maintained for at least five years from its date of generation.

Generally, reports are due 30 days after the close of the period that the reports cover. Also, the reporting periods are on a calendar basis: monthly reports shall cover a calendar month, quarterly reports shall cover a calendar quarter, six-month reports shall cover January through June and July through December, and annual reports shall cover a calendar year.

Monthly Reports: The monthly reports include a wide range of data collected during the month that are required to be submitted monthly by various permits, orders and regulations. A large part of the monthly report comprises continuous emission monitoring system (CEMS) performance data which provides information about the duration and nature of CEMS downtime, changes made to the CEMS, total operating time and dates of CEMS audits or certifications. PSR often provides these elements more frequently than the minimum reporting frequency required by underlying regulations. Another significant element of monthly reports is the disclosure of deviations from required monitoring and exceedance of emission limits.

Quarterly and Semiannual Reports: The refinery is required to submit quarterly reports under 40 CFR 61 Subpart FF certifying that the company met all applicable Subpart FF requirements. These include, but are not limited to, visual inspections of seals, hatches and openings, identification of API floating roof seal gap measurements, an indication that seal gaps were repaired within required timeframes, an indication that all flare pilots were lit at all times when process gas was sent to the flare, carbon canisters were replaced within required timeframes, and certification that all required inspections have been performed. Fenceline benzene monitoring reports are submitted quarterly via EPA's CEDRI electronic reporting system.

The refinery is required to submit semiannual reports under 40 CFR 63 Subparts CC and UUU which should address any compliance exceptions to the requirements of the rules including, but not limited to: delay of repair of storage tanks, failure of any pilot light on a flare, and leak detection and repair monitoring summaries. In addition, semiannual reports required under 40 CFR 60 Subparts J/Ja require flare root cause analysis and corrective action analysis. Semiannual reports required under 40 CFR 60 Subpart QQQ require reporting the date and type of defect found in the Individual Drain Systems along with the corrective action taken.

The leak detection and repair (LDAR) program (required under multiple regulations) also requires a semiannual report that summarizes 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: 40 CFR 61 Subpart FF requires an annual report that summarizes the total annual benzene quantity from facility waste, identifies each waste stream and whether or not the waste stream will be controlled for benzene, and, for uncontrolled streams, lists parameters describing the uncontrolled streams along with the annual benzene quantity for each.

Additionally, the refinery is required to submit an annual report under 40 CFR 61 Subpart FF that includes the results of annual monitoring per Method 21, summary of annual inspections of individual drain systems and vacuum trucks.

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

Compliance Certifications: All required monitoring reports must be certified by a responsible official of the truth, accuracy, and completeness of the reports. Where an applicable requirement requires reporting more frequently than once every six months, the responsible official's certification need only to 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 permit, the compliance status, whether the compliance was continuous or intermittent, and the methods used for determining the compliance status.

## 1.5 Emission Inventory

Each year all major sources are required to submit an air pollution emissions inventory upon request of the NWCAA. This report includes criteria air pollutants, hazardous air pollutants (HAP), and greenhouse gas (GHG) emissions. The NWCAA publishes an emissions inventory report each year that includes emissions summaries for all of the large industrial facilities located within Whatcom, Skagit and Island counties; emissions from PSR are also included.

Table 1-3 and 1-4 summarizes the last six years of available emissions data reported by PSR. 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.

Table 1-3 lists criteria pollutants, total HAP (THAP), ammonia and greenhouse gas (GHG) emissions. Table 1-4 lists all hazardous air pollutants (HAP) and toxic air pollutants (TAP) emitted at or above 1 ton per year at least once during that six-year period, as reported by PSR in annual emission inventories.

**Table 1-3: Annual Actual Emissions from PSR**

| Pollutant | Calendar Years Emissions (tons) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| $PM_{10}$ | 193 | 183 | 207 | 177 | 182 | 191 | 176 |
| $SO_2$ | 466 | 349 | 233 | 246 | 225 | 228 | 215 |
| NOx | 1,857 | 1,501 | 1,337 | 1,370 | 1,297 | 1,393 | 1,165 |
| VOC | 575 | 392 | 463 | 473 | 429 | 324 | 475 |
| CO | 560 | 633 | 510 | 546 | 501 | 550 | 571 |
| THAP | 7.2 | 13.6 | 16.1 | 14.7 | 11.8 | 13.5 | 15.2 |
| $NH_3$ | 4.5 | 4.2 | 2.1 | 1.3 | 2 | 4 | 5 |
| GHG[a,b] | 802,823 | 697,725 | 789,505 | 777,967 | 733,083 | 712,083 | 723,968 |

[a] GHG from Cogeneration Units only
[b] Reported as $CO_2e$, in units of metric tons

**Table 1-4: Annual Actual Hazardous and Toxic Emissions from PSR**

| Pollutant | Calendar Years Emissions (tons) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| Toluene[1] | 1.0 | 2.1 | 2.6 | 2.7 | 2.2 | 2.4 | 3.5 |
| n-Hexane[1] | 2.3 | 2.7 | 3.3 | 5.0 | 3.3 | 3.6 | 3.3 |
| Isooctane[1] | 0.7 | 3.4 | 4.2 | 1.4 | 1.1 | 2.0 | 2.2 |
| Xylene[1] | 0.7 | 2.1 | 2.5 | 1.8 | 1.5 | 1.7 | 2.1 |
| Formaldehyde[1] | 0.7 | 0.9 | 0.9 | 1.0 | 0.9 | 1.0 | 1.0 |
| Benzene[1] | 1.0 | 1.1 | 1.4 | 1.7 | 1.3 | 1.4 | 1.4 |
| Cyclohexane[2] | 0.1 | 0.5 | 0.5 | 1.7 | 0.7 | 0.8 | 0.8 |
| $H_2SO_4$[2] | 39.4 | 31.6 | 30.6 | 30.8 | 30.6 | 30.6 | 27.1 |

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

## 1.6 Performance Tests and Continuous Emission Monitors

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 1-5 contains information on the tests performed during the last air operating permit term.

Note that numerous emission units at PSR are not source tested because the units are equipped with Continuous Emission Monitors (CEMs). Table 2-11 lists the locations of the CEMs and what pollutants they monitor for.

**Table 1-5: Performance Test Summary**

| HTU2 – H2S Stripper & Fractionator Reboilers (11H-102 & 11H-103) | | | | |
|---|---|---|---|---|
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 4/7/15 | NOx | 0.06 lb/MMBtu | Inconclusive – 99.3% of limit, test method deviations – retest required | Every 5 years |
| 8/26/15 | NOx | 0.06 lb/MMBtu | Pass | Every 5 years |
| 8/20/20 | NOx | 0.06 lb/MMBtu | Pass | Every 5 years |
| **FCCU & WGS** | | | | |
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 4/14/15 | $PM_{10}$ | 0.02 gr/dscf @ 7% $O_2$ | Pass | Annually |
| | | 1 lb/1000 lb coke | Pass | |
| | | 202 tpy | Pass | |
| 5/31/16 | $PM_{10}$ | 0.02 gr/dscf @ 7% $O_2$ | Pass | Annually |
| | | 1 lb/1000 lb coke | Pass | |
| | | 202 tpy | Pass | |
| 5/12/17 | $PM_{10}$ | 0.02 gr/dscf @ 7% $O_2$ | Pass | Annually |
| | | 1 lb/1000 lb coke | Pass | |
| | | 202 tpy | Pass | |
| 5/30/18 | PM | 0.2 gr/dscf | Pass | Annually |
| | | 1 lb/1000 lb coke | Pass | |
| | $PM_{10}$ | 0.02 gr/dscf @ 7% $O_2$ | Pass | |
| | | 202 tpy | Pass | |
| 5/30/19 | PM | 0.2 gr/dscf | Pass | Annually |
| | | 1 lb/1000 lb coke | Pass | |
| | $PM_{10}$ | 0.02 gr/dscf @ 7% $O_2$ | Pass | |
| | | 202 tpy | Pass | |
| 6/30/20 | PM | 0.2 gr/dscf | Pass | Annually |
| | | 1 lb/1000 lb coke | Pass | |
| | $PM_{10}$ | 0.02 gr/dscf @ 7% $O_2$ | Pass | |
| | | 202 tpy | Pass | |
| **Truck Rack Vapor Recovery & Incinerator** | | | | |
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 10/5/15 | VOC | 10 mg TOC/L gasoline loaded | Pass | Biennial |
| | | 35 mg TOC/L gasoline loaded | | |
| | | 90% VOC destruction efficiency | Pass | |
| 9/20/17 | VOC | 10 mg TOC/L gasoline loaded | Pass | Biennial |
| | | 35 mg TOC/L gasoline loaded | | |
| | | 90% VOC destruction efficiency | Pass | |
| 9/18/19 | VOC | 10 mg TOC/L gasoline loaded | Pass | Biennial |
| | | 35 mg TOC/L gasoline loaded | | |

| | | | | |
|---|---|---|---|---|
| | | 90% VOC destruction efficiency | Pass | |
| **VPS – Vacuum Charge Heater (1A-F8)** | | | | |
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 11/10/15 | NOx | 0.05 lb/MMBtu | Pass | Every 5 years |
| 8/18/20 | NOx | 0.05 lb/MMBtu | Pass | Every 5 years |
| | | 21 tpy | Pass | |
| **DCU – Charge Heater (15F-100)** | | | | |
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 11/12/15 | NOx | 0.07 lb/MMBtu | Pass | Every 5 years |
| | | 50 ppmdv | Pass | |
| 8/18/20 | NOx | 0.07 lb/MMBtu | Pass | Every 5 years |
| | | 50 ppmdv @ 5% $O_2$ | Pass | |
| | | 39.5 tpy | Pass | |
| **HTU3 – CDHDS Heater (60-F201)** | | | | |
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 4/19/18 | NOx | 0.035 lb/MMBtu | Pass | Every 5 years |
| 12/11/19 | NOx | 0.03 lb/MMBtu | Pass | Annually[1] |
| 9/24/20 | NOx | 0.03 lb/MMBtu | Pass | Annually[1] |
| **HTU1 – Heaters (7C-F4 & 7C-F5)** | | | | |
| **Date** | **Pollutant** | **Limit** | **Result** | **Frequency** |
| 10/9/18 | NOx | 0.07 lb/MMBtu | Pass | Every 5 years |

Based on a review of the stack test results since the last AOP renewal, NWCAA concluded that testing frequency was sufficient and that tests demonstrate an adequate margin of compliance therefore, no changes to testing, monitoring, recordkeeping or reporting were warranted.

## 1.7 Miscellaneous Refinery Non-Process Activities

There are several regulated activities that can 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 employs open burning during the instruction of the refinery's emergency response personnel.  Open burning activities are subject to state and NWCAA requirements.  Abrasive blasting and painting occurs during maintenance and repair activities of tanks and equipment at the refinery to remove old and chipped paint and surface contaminants.  This activity is subject to state and NWCAA regulations.  Gasoline is dispensed from one pump for fueling the refinery's fleet of vehicles used on site, regulated under NWCAA gasoline dispensing regulations.  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.

[1] OAC requires performance testing on an annual basis.  After two consecutive annual tests which indicate compliance with emissions limits have been performed, PSR may reduce the testing frequency to once every five years.  If any single test indicates noncompliance with emissions limits, the testing frequency resets to annual.

## 1.8 Insignificant Emission Units

The refinery has emission units and activities determined to be insignificant under WAC 173-401-530, -532, and -533. In general, they 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 PSR are listed in Section 4.2.9 of this SofB.

# 2. REGULATORY APPLICABILITY

This portion of the Statement of Basis identifies and discusses specific regulatory applicability of a wide range of local, state and federal programs and requirements. Tables 2-1 through 2-3 list federal requirements, sorted first by regulation, then by which process unit(s)/emission unit(s) trigger the requirements, with any specific comments.

NSPS apply to the control of criteria pollutants emitted from specific types of sources that have been constructed or modified after the applicability date of each rule. Criteria air pollutants are those associated with national ambient air quality standards and include carbon monoxide (CO), sulfur dioxide ($SO_2$), nitrogen oxides (NOx), particulate matter ($PM/PM_{10}$), and volatile organic compounds (VOC) for ozone.

NESHAP apply to the emission of hazardous air pollutants (HAPs) at existing sources, regardless of the construction or modification dates. NESHAPs were developed to reduce emissions, by industrial source category, for the 187 HAPs specified by Congress.

**Table 2-1: 40 CFR Part 60 New Source Performance Standards (NSPS)**

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Comments |
|---|---|---|---|---|
| A | Flares | Flares | N, S & E Flares | General control device & work practice requirements. |
| Db | Combustion Turbine | Cogens | CT-1, -2, & -3 Duct Burners | 163 MMBtu/hr, each.<br>Triggered at construction for PM & NOx: CT-1 & -2 10/26/90, CT-3 8/7/91.<br>Combustion turbines are not affected sources, only the duct burners are subject.<br>Erie City Boiler constructed prior to 8/17/71, so not subject to D, Da, or Db. |
| J | Fuel Gas Combustion Unit | VPS | Vac Charge Heater (1A-F8) | Triggered with replacement, OAC 684 in 1999 |
| | | DCU | Charge Heater (15F-100) | Triggered with replacement, OAC 628 in 1997 |
| | | FCCU | CO Boilers (COB-1 & -2) | Triggered when ESP replaced with WGS 1/5/05 |
| | | HTU1 | Charge & Fractionator Reboiler (7C-F4/F5) | Triggered J at construction 9/29/91 |
| | | HTU2 | $H_2S$ Stripper & Fractionator Reboiler (11H-102 &-103) | Triggered J at construction 11/16/97 |
| | | HTU3 | CDHDS Heater (60-F201) | Triggered J at construction 1/20/03 |
| | | SRU | SRU 3 & 4 Incinerators | These units triggered for both fuel gas combustion devices and as Claus sulfur recovery plants.<br>Construction dates: SRU3 6/17/99, SRU4 5/5/03.<br>Note: OAC 828b limits supplemental fuel to natural gas except during periods of natural gas curtailment. |

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Comments |
|---|---|---|---|---|
| | | Cogens | CT-1, -2 & -3 - Duct burners | 163 MMBtu/hr, each.<br>Triggered at construction for SO2: CT-1 & -2 10/26/90, CT-3 8/7/91 (163 MMBtu/hr, each).<br>Combustion turbines not affected sources, just the duct burners are subject |
| | | RP&S | Vapor Combustion Device (23NF1) at Gas/Diesel Truck Loading Rack | Modified to add vapor combustor 4/30/93.<br>Considered triggered/compliance on 12/31/01 |
| | FCCU | FCCU | Catalyst Regenerator | Triggered NSPS J with modification on 2/23/98 but did not triggered for $SO_2$.<br>Consent Decree brought in all pollutants (including SO2), memorialized in CO 10 |
| | SRUs | SRUs | SRU3 & 4 | These units triggered for both fuel gas combustion devices and as Claus sulfur recovery plants.<br>Construction dates: SRU3 6/17/99, SRU4 5/5/03. |
| Ja | Flares | N & S Flares | N & S | Triggered Ja with construction of the Benzene Reduction Project on 4/5/11 |
| | | E Flare | E | |
| K | Storage Tanks | EFR | TK-4 thru -6, & -19 | |
| | | IFR | TK-36 | |
| Ka | Storage Tanks | FR | TK-18 & -37 | |
| Kb | Wastewater Tanks | EFR | TK-72 & -73 | Subject per letter 10/13/04 |
| | | IFR | TK-60, -61, -62, -70 & -71 | |
| | | Open Top | TK-76 | out of service |
| | Storage Tanks | EFR | TK-38, -503 & -505 | Nonene tank vapor pressure is limited through the OAC to be less than 0.75 psia, so nonene storage tanks (TK-80 thru -82) do not trigger NSPS Kb. |
| | | IFR | TK-12 thru -14 | Subject per letter 10/13/04 |
| | | | TK-39 & -85 | Ethanol tank TK-85 subject due to construction date, size & vapor pressure > 0.75 psia |
| GG | Combustion Turbines | Cogens | CT-1, -2, & -3 Combustion Turbines | 450 MMBtu/hr, each.<br>Triggered at construction: CT-1 & -2 10/26/90, CT-3 8/7/91 |

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Comments |
|---|---|---|---|---|
| VV[1] | Components at SOCMI process units in VOC service | Nonene (triggered at construction 1991) | | Revised definition of "process unit" in NSPS VV has been stayed & reverts back to the previous definition, which does not include loading racks - Nonene truck & railcar loading rack is not subject to LDAR requirements under NSPS VV.<br>The nonene unit itself qualifies as SOCMI under NSPS, but is not subject to NSPS NNN - does not have a vent stream that is released to atmosphere (directly or indirectly).<br>Units subject to VV are excluded from Subpart GGG & GGGa. |
| XX | Loading Rack | RP&S | Gas/Diesel Truck Loading Rack (LR-1) | Terminal modified after (12/17/80).<br>If subject to RMACT1 & XX, only need comply with RMACT1, which applies a modified Subpart R, which references Subpart XX. |
| | Vapor Combustor | RP&S | Vapor Combustion Device (23NF1) | Terminal modified after (12/17/80).<br>If subject to RMACT1 & XX, only need comply with RMACT1, which applies a modified Subpart R, which references Subpart XX. |
| 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) | VPS | | Triggered for unit with replacement of 1A-F8, OAC 684 in 1999 |
| | | DCU | | |
| | | FCCU | | Triggered with Vertical Riser Project OAC 623, in 1998 |
| | | CPU | | Triggered with Vertical Riser Project OAC 623, in 1998 |
| | | Alky1 | | Triggered at construction OAC 887, in 2004 |
| | | BHU | | Triggered at construction OAC 772, in 2001 |
| | | HTU2 | | |
| | | HTU3 | | |
| | | ISOM | | Triggered at construction in 2004 |
| | | SRUs | | Triggered at construction: SRU3 6/17/99, SRU4 5/5/03 |
| | | FGR | | |
| | | Units that have not triggered | | Cogens not affected source - no physical modification occurred when Shell took ownership.<br>Gas/Diesel Truck Loading Rack & Diesel Railcar Loading Rack are not affected sources – definition of process unit does not include loading racks.<br>Compressors in hydrogen service are exempted from monitoring requirements. |
| | | CRU1 | | |

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Comments |
|---|---|---|---|---|
| GGGa[2] | Components in VOC service (triggered after 11/7/06) | BRU (triggered at construction 7/22/09) | | Cogens not an affected source because no physical mod occurred when Shell took ownership.<br>Ethanol storage tank not subject - not considered part of a refinery production unit. |
| QQQ | Process Drains in VOC service | VPS | | Triggered with VPS PI Project OAC 1253, in 2016 |
| | | DCU | | Triggered with OAC 628a, in 1998 |
| | | FCCU | | Triggered with Vertical Riser Project OAC 623, in 1998 |
| | | Nonene | | Triggered at construction OAC 296, in 1991.<br>Construction of the nonene processing unit involved installation of new drains - even though a SOCMI unit under NSPS, because it is located at petroleum refinery, drains are subject to NSPS QQQ. |
| | | HTU2 | | Triggered at modification |
| | | HTU3 | | Modified unit |
| | | ISOM | | Triggered at construction 2004 |
| | | BRU | | Triggered at construction 7/22/09 |
| | | Diesel Railcar Loading Rack | | Modified unit |
| | | Nonene Truck & Railcar Loading Rack | | Triggered at construction OAC 296, in 1991.<br>Construction of the nonene truck and railcar loading facility involved installation of new drains - even though a SOCMI unit under NSPS, because it is located at a petroleum refinery, drains subject to NSPS QQQ. |
| | | FGR | | Modified unit |
| | | EFRs TK-503 & -505 | | Triggered at constructed under OACs 1291 and 1301, in 2018 and 2019 respectively.<br>Construction of TK-503 & -505 involves installation of new drains.<br>Under NSPS, because it is located at a petroleum refinery, drains subject to NSPS QQQ. |
| | Oil-Water Separators | EP | DAF3 | DAF3 constructed after 5/4/87 & manages a Group 1 wastewater stream regulated under RMACT1, so is only required to comply with RMACT1, which references BWON. |
| IIII | Compression Ignition Internal | Main Control Room | Emergency Generator (30LEG6) | New (manufactured after 4/1/06 & commenced construction after 7/11/05) engine subject to 40 CFR 60 Subpart IIIII. |

[2] "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 | Radio Tower | Emergency Generator (30LEG7) | |
| | | EP | Outfall Pump (9QG68) | New (manufactured after 4/1/06 & commenced constructed after 7/11/05), non-emergency (> 100 hr/yr) engine, rated at 500 hp. |

**Table 2-2: 40 CFR 61 National Emission Standards (NES)**

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Discussion |
|---|---|---|---|---|
| FF | Process Drains | VPS | | Applies to all wastewater operations at a refinery with benzene concentration > 10 ppm |
| | | DCU | | |
| | | FCCU | | |
| | | CPU | | |
| | | Nonene | | |
| | | CRU1 | | |
| | | CRU2 | | |
| | | Alky1 | | |
| | | Alky2 | | |
| | | BHU | | |
| | | HTU1 | | |
| | | HTU2 | | |
| | | HTU3 | | |
| | | ISOM | | |
| | | BRU | | |
| | | Gas/Diesel Truck Loading Rack | | |
| | | Nonene Truck & Railcar Loading Rack | | |
| | | Flares | | |
| | | FGR | | |
| | | Misc Tank Farm (incl TK-503 & -505) | | |
| | Wastewater Tanks | ETPPDF | EFRs TK-72 & -73 | |
| | | | IFRs TK-60, -61, -62, -70 & -71 | |
| | Oil-Water Separators | | API Separator | |
| | Closed Vent Systems & Control Devices | | DAF Units 1&2 | |
| | | | DAF Unit 3 | |
| | | | Tank 74 Sump | |
| | | | Sewer Lines & Covers | |
| | | | Surge Sump | |
| | | | Lift/Pump Station (2 units) | |
| | Marine Terminal | Other RP&S Areas | Offshore facility | |

## Table 2-3: 40 CFR 63 National Emission Standards for Hazardous Air Pollutants (NESHAP)

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Discussion |
|---|---|---|---|---|
| A | Flares | Flares | N, S & E Flares | |
| Y | Marine Terminal | Other RP&S | Marine Terminal - Offshore Facility | Subject to Y, but exempt from requirements because existing terminal, located > 0.5 miles offshore |
| CC | DCU | DCU | Drum Depressurizing | Part of Residual Risk & Technology Review. |
| | Misc. Process Vents | VPS | Desalter Waterwash Surge Drum Vent (1A-C46) | Triggered due to HAP content > 20 ppm |
| | | DCU | Coker Frac OH Accum Vent (15-C4) | |
| | | FCCU | Intermediate Sep Bottoms Drum Vent (4B-C35) | |
| | | | 1st Stage Compressor In-line Sep Vent (4B-C102) | |
| | | CPU | Flare KO Drum Vent (5J-C56) | |
| | | | Flare KO Drum Vent (5J-C85) | |
| | | CRU1 | Feed Surge Drum Vent (6D-C8) | |
| | | CRU2 | Feed Surge Drum Vent (10F-104) | |
| | | | Platformate Splitter Receiver Vent (10F-119) | |
| | | Alky2 | Acid Vapor Caustic Scrubber Vent (12F-115) | |
| | | HTU2 | Fractionator Accumulator Vent (1F-209) | |
| | 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.<br><br>Part of Residual Risk & Technology Review. |
| | Atmospheric Pressure Relief Devices | VPS | Atm Tower (1A-C1): 11 PRDs | Pressure relief devices that relief to atmosphere.<br><br>Part of Residual Risk & Technology Review. |
| | | FCCU | Main Fractionator (3B-C1): 9 PRDs | |
| | | HTU1 | Fractionator (7C-C5): 5 PRDs | |
| | Loading Racks | RP&S | Gas/Diesel Truck Loading Rack (LR-1) | Marine vessel loading not subject to 40 CFR 63 Subpart CC - operation does not meet applicability criteria under 40 CFR 63 Subpart Y |
| | Vapor Combustor | RP&S | Vapor Combustion Device (23NF1) | Considered a thermal oxidizer |

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Discussion |
|---|---|---|---|---|
| | Flares | Refinery-wide | Closed Vent Systems Routed to Flares | Process Vents and Pressure Relief Devices refinery-wide |
| | Wastewater Tanks | Group 1 | EFRs TK-72 & -73 | By definition, wastewater tanks not storage tanks - overlap provisions with NSPS (i.e., K, Ka, Kb) don't apply to wastewater tanks. |
| | | | IFRs TK-60, -61, -62, -70 & -71 | |
| | Storage Tanks | Group 1 | EFR TK-1 thru -6, -11, -17, -19, -21, -22, -24, -29, -38, -43, -50 thru -52, -55, -58, -72, -73, -503, -505 | |
| | | | IFR TK-12 thru -14, -23, -28, -30, -36, -39, -53, -54, -60, -61, -62, -70, -71 | |
| | | Group 2 | IFR TK-85, -15D-100A thru -C | Ethanol storage tank (TK-85) contains or contacts listed HAP, but at concentration < 4% - Group 2 tank. |
| | | | EFR TK -15, -34, -44, -45, -59, -80 thru -82 | Nonene unit initial feedstock contains HAPs, therefore the product has the potential to contain one or more listed HAPs - nonene storage tanks (TK-80 thru -82) Group 2 tanks. |
| | | | FR TK-10, -16, -18, -25 thru -27, -31 thru -33, -35, -37, -40 thru -42, -49, -56, -57, -504 | |
| | Refinery | Refinery Fenceline | | Required by Residual Risk & Technology Review |
| | Heat Exchangers In HAP service | Cooling Tower 1 & 2 | VPS | No heat exchangers at Cogen in HAP service. |
| | | | DCU | |
| | | | FCCU | |
| | | | CPU | |
| | | | CRU1 | |
| | | | CRU2 | |
| | | | Alky1 | |
| | | | Alky2 | |
| | | | HTU1 | |
| | | | HTU2 | |
| | | | HTU3 | |
| | | | BRU | |
| | Process Drains in HAP service | Group 1 | FGR; EP | Over 1700 process drains refinery-wide subject to CC (It is PSR's responsibility to track MRR). |
| | | Group 2 | Refinery-wide | |
| | Components in HAP service (existing refinery that is a major source | VPS | | The Nonene unit not subject - does not contain/contact material w/ 5% by wt HAP. |
| | | DCU | | |
| | | FCCU | | |
| | | CRU1 | | |

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Discussion |
|---|---|---|---|---|
| | of HAP = streams with > 5% listed HAP by wt | CRU2 | | Cogens not "petroleum refining process units" so not affected source.<br>Diesel Railcar Loading Rack not subject - does not contain/contact material w/ 5% by wt HAP.<br>Ethanol Unloading & Storage fugitive components not subject -does not contain/contact material w/ 5% by wt HAP.<br>Marine vessel loading does not trigger 40 CFR 63 Subpart CC - operation does not meet the applicability criteria under 40 CFR 63 Subpart Y.<br>Compressors in hydrogen service are explicitly exempt from the monitoring requirements. |
| | | Alky1 | | |
| | | Alky2 | | |
| | | BHU | | |
| | | HTU1 | | |
| | | HTU2 | | |
| | | HTU3 | | |
| | | ISOM | | |
| | | BRU | | |
| | | SRUs | | |
| | | Gas/Diesel Truck Loading Rack | | |
| | | Flares | | |
| | | FGR | | |
| | | Misc Tank Farm (Including TK-503 & -505) | | |
| 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) |
| | CRUs | CRU1 | Catalyst Regeneration Drum Vent | Organic HAP emissions during depressurizing & purging of the CRUs to be controlled by purging the unit to the flare that meets 63.11(b).<br>Inorganic HAP emissions as HCl during coke burn-off & catalyst regeneration must be reduced to 30 ppmvd, @ 3% oxygen.<br>Part of Residual Risk & Technology Review. |
| | | CRU2 | Catalyst Regeneration Drum Vent | |
| | SRUs | SRU | SRU 3 & 4 | |
| YYYY | Cogens | Cogens | CT-1, -2, & -3 - Combustion Turbines | Existing units constructed: CT-1 & -2 10/26/90, CT-3 8/7/91, but no applicable requirements to the CTs. |
| ZZZZ | ICE | Control Room | #2 Generator (30LEG2) | Existing (installed prior to 6/12/06) emergency engines, rated at < 500 hp.<br>Not subject to NSPS IIII. |
| | | BOHO | Emergency Firewater Pump (33PGE3) | |
| | | | Firewater Pumps (33PGE14 & 33PGE15) | |
| | | Wharf | Standby Generator (30LEG5) | Existing (installed prior to 12/19/06) emergency engine, located at a major |

| Subpart | Affected Facility | Process Unit | Emission Unit ID | Discussion |
|---|---|---|---|---|
| | | | | source of HAPs, rated at > 500 hp, does not operate nor is contractually obligated to be available for more than 15 hours per calendar year - per 63.6590(b)(3), not required to meet 40 CFR 63 Subpart ZZZZ.<br>Not subject to NSPS IIII. |
| | | Main Control Room | Emergency Generator (30LEG6) | New (constructed after 6/12/06) emergency engines located at a major source of HAPs, rated at < 500 hp - per 63.6590(c), comply by meeting the requirements of 40 CFR 60 Subpart III |
| | | Radio Tower | Emergency Generator (30LEG7) | |
| | | EP | Outfall Pump (9QG68) | New (manufactured after 4/1/06), non-emergency (operated > 100 hr/yr) engine. |
| DDDDD | Boilers | Utilities | Erie City Boiler (31GF1) | CO Boilers are subject to 40 CFR 63 Subpart UUU, so not subject per 63.7491(h).<br>Heat recovery steam generating units (HRSG) at the Cogens are waste heat boilers which are excluded from the definition of "boiler" as affected sources. |
| | Process Heaters | VPS | Gas Oil Tower Heater (1A-F4) | |
| | | | Atm Charge Heaters (1A-F5/F6) | |
| | | | Vac Charge Heater (1A-F8) | |
| | | DCU | Charge Heater (15F-100) | |
| | | CRU2 | Charge & Interheater #1 & 2 (10H-101, -102, & -103) | |
| | | | Stabilizer Reboiler (10H-104) | |
| | | HTU1 | Charge & Fractionator Reboiler (7C-F4/F5) | |
| | | HTU2 | Charge Heater (11H-101) | |
| | | | $H_2S$ Stripper & Fractionator Reboiler (11H-102 &-103) | |
| | | HTU3 | CDHDS Heater (60-F201) | |
| PPPPP | ICE | Refinery Lab | Engine Test Stand (5 engines) | Existing octane test engines (installed prior to 5/14/02) subject to PPPPP, but don't have to meet requirements of PPPPP.<br>These units are not subject to ZZZZ |

More complex regulatory applicability specific to refineries, along with applicability where overlapping standards exist, be they federal, state or local standards, are discussed in depth in Section 2.1. Regulatory programs that are equipment-specific and may apply to emission units across numerous process (e.g., boilers and generators) are discussed in Section 2.2. Requirements that might appear to apply at PSR, but are not triggered for any process units or equipment are discussed in Section 2.3.

Refer to Section 3 for a more detailed discussion of each process and its emission unit(s).

## 2.1 Applicability and Overlap of Refinery Standards

### Refinery Standards

The following standards are refinery-specific and apply broadly across the refinery, to various refinery processes, process units or equipment:

- 40 CFR 60 Subparts J and Ja Standards of Performance for Petroleum Refineries
- 40 CFR 60 Subparts K, Ka, and Kb Standards of Performance for Storage Vessels for Petroleum Liquids/Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)
- 40 CFR 60 Subparts GGG and GGGa Equipment Leaks of VOC in Petroleum Refineries
- 40 CFR 60 Subpart QQQ VOC Emissions from Refinery Wastewater Systems
- 40 CFR 61 Subpart FF (aka BWON) Benzene Waste Operations
- 40 CFR 63 Subpart Y Marine Tank Vessel Loading Operations
- 40 CFR 63 Subpart CC (aka Refinery MACT 1) Petroleum Refineries
- 40 CFR 63 Subpart UUU (aka Refinery MACT 2) Petroleum Refineries - CCU, CRU, and SRU
- NWCAA Section 580.2 Petroleum Refineries

To reduce overlaps between NWCAA Sections 560 and 580 and similar requirements under federal regulations, the NWCAA adopted NWCAA 580.26 and 580.37(specific to tanks) into its current rules, as follows:

- NWCAA 580.37 exempts all tanks subject to NWCAA 580.3 or 580.9 and all tanks that are exempt by NWCAA 580.26 from the requirements in NWCAA Section 560.
- NWCAA 580.26 exempts any petroleum refinery process unit, storage facility, or other operation subject to federal VOC or HAP standards from NWCAA 580.3 through 580.5, and NWCAA 580.8 through 580.10

However, NWCAA 580.26 is not in the SIP and, as such, is not federally enforceable. An earlier version of NWCAA 580 is included in the SIP, and that version does have applicable requirements (no 580.26 exemption in the SIP version of the rule). Therefore, in the AOP, references to NWCAA Section 580.3 through 10 for 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) and for those that are not subject to other federal rules are dated with both the date of the SIP version as federally enforceable and the date of the current rule as state only.

Frequently, more than one standard may apply to a process, process unit, or piece of equipment. In some instances through overlap provisions, the regulation may specify which standard applies (usually the most stringent) in the event that the refinery process unit or equipment is subject to multiple standards. In other instances, the standard may provide the option for the refinery to elect to meet the requirements of one standard in order to comply with the requirements of the other standard(s).

In some cases, refinery standards may require compliance with other non-refinery specific standards, to which the facility is not directly subject, such as:

- 40 CFR 60 Subparts VV and VVa Equipment Leaks of VOC in SOCMI
- 40 CFR 60 Subpart XX Standards of Performance for Bulk Gasoline Terminals
- 40 CFR 63 Subpart G Organic HAP Emissions from SOCMI for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

- 40 CFR 63 Subpart R Gasoline Distribution Facilities
- 40 CFR 63 Subpart WW Storage Vessels – Control Level 2

On December 1, 2015, EPA published substantial revisions to refinery standards under 40 CFR 60 Subparts J and Ja and 40 CFR 63 Subparts CC and UUU (Refinery MACT 1 & 2) reflecting their Refinery Sector Risk and Technology Review (RTR) initiative. Following the RTR revisions, EPA received several petitions for reconsideration. To address concerns raised in the petitions, EPA made additional revisions to Refinery MACT 1 & 2, dated:

- July 13, 2016,
- November 26, 2018, and
- February 4, 2020.

With the issuance of the 2nd renewal of the AOP, all aforementioned revisions have been incorporated.

A discussion of how applicability is determined follows.

### 2.1.1 40 CFR 60 Subparts J and Ja – Petroleum Refineries

NSPS Subpart J establishes carbon monoxide, sulfur dioxide, and particulate matter emission limits and associated requirements applicable to fluid catalytic cracking unit (FCCU) catalyst regenerators constructed or modified after June 11, 1973; and sulfur dioxide emission limits and associated requirements for fuel gas combustion devices constructed or modified after June 11, 1973 as well as for all Claus sulfur recovery plants with a design capacity for sulfur feed of greater than 20 long tons per day constructed or modified after October 4, 1976.

The FCCU, two sulfur recovery units (SRUs) and fuel gas combustion devices are subject to NSPS Subpart J because they were either constructed, reconstructed or modified after the applicability date or were mandated affected sources under the Heater and Boiler Consent Decree, memorialized in NWCAA Compliance Order (CO) 07.

NSPS Subpart Ja establishes emissions limits and associated requirements applicable to FCCUs, fluid coking units (FCU), delayed coking units (DCU), fuel gas combustion devices, flares, and sulfur recovery plants generally constructed, modified, or reconstructed after May 14, 2007. At PSR, the flares are the only units to have triggered NSPS Subpart Ja applicability.

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

**Fuel Gas Combustion Devices:** As can be seen in Table 2-4, fourteen of the refinery fuel gas combustion devices (e.g., heaters and boilers) were constructed, reconstructed, or modified within the appropriate date range, triggering NSPS Subpart J. The Heater and Boiler Consent Decree mandated that all heaters and boilers are affected sources under NSPS Subpart J, the requirement of which was memorialized in NWCAA Compliance Order (CO) 07. Therefore, the other nine units that have not yet been reconstructed or modified to trigger NSPS Subpart J are now affected sources and must comply with NSPS Subpart J.

**Table 2-4: Subpart J Regulatory Applicability for Combustion Devices**

| Combustion Device | Subpart J | CO 07 |
|---|---|---|
| Gas Oil Tower Heater (1A-F4) | | X |
| Atmospheric Charge Heater (1A-F5) | | X |
| Atmospheric Charge Heater (1A-F6) | | X |
| Vacuum Charge Heater (1A-F8) | X | |
| Charge Heater (15F-100) | X | |
| CO Boiler (COB-1) | X | |
| CO Boiler (COB-2) | X | |
| Charge Heater (10H-101) | | X |
| Interheater #1 (10H-102) | | X |
| Interheater #2 (10H-103) | | X |
| Stabilizer Reboiler (10H-104) | | X |
| Charge Heater (7C-F4) | X | |
| Fractionator Reboiler (7C-F5) | X | |
| Charge Heater (11H-101) | | X |
| $H_2S$ Stripper Reboiler (11H-102) | X | |
| Fractionator Reboiler (11H-103) | X | |
| CDHDS Heater (60-F201) | X | |
| Erie City Boiler 1 (31GF1) | | X |
| Truck Rack Vapor Combustor (23NF1) | X | |
| Duct Burners for Cogens 1, 2, & 3 | X | |

**Sulfur Recovery Units (SRUs):** The refinery operates two SRUs – Unit 3 constructed in 1999 and Unit 4 constructed in 2003 – both subject to NSPS Subpart J $SO_2$ requirements. As allowed in 60.100(e), PSR meets the $SO_2$ limit in NSPS J by complying with the $SO_2$ limit in NSPS Ja. NSPS Ja provides calculated adjustment to the $SO_2$ emission limit for SRUs that operate oxygen-enrichment to the Claus burners. To demonstrate compliance with the oxygen-enrichment adjusted $SO_2$ limit, PSR uses a continuous emission monitoring system (CEMS) to measure and record $SO_2$ at the incinerator stacks, and a continuous parameter monitoring systems (CPMS) to measure and record the volumetric gas flow rate of ambient air and oxygen-enriched gas supplied to the Claus burner and calculates the hourly average $O_2$ concentration of the air-oxygen mixture. This $O_2$ concentration is then used to adjust the $SO_2$ emission limitation to account for the oxygen-enrichment.

PSR began implementing the oxygen adjustment for the SRUs January 30, 2019. Also, because the SRUs use refinery fuel gas as a supplemental fuel, the SRUs also qualify as fuel gas combustion devices under NSPS Subpart J; to comply, fuel gas $H_2S$ concentration is monitored at the main fuel gas mix drum.

**Fluid Catalytic Cracking Unit (FCCU):** In 1998, the FCCU was modified in the Vertical Riser Project, which triggered NSPS Subpart J for carbon monoxide (CO), particulate matter, and opacity (NWCAA issued OAC 623). Because there was no increase in $SO_2$ emissions, NSPS Subpart J was not triggered for $SO_2$. However, the Equilon Consent Decree mandated that the FCCU is an affected source for all pollutants under NSPS Subpart J; the requirements of which are memorialized in NWCAA Compliance Order (CO) 10. Note also that the CO Boilers are listed in Table 2-1; the CO Boilers use refinery fuel gas as supplemental fuel which qualifies them as fuel gas combustion devices under NSPS Subpart J; to comply, fuel gas $H_2S$ concentration is monitored at the main fuel gas mix drum.

**Flares:** PSR operates three flares (east, north, and south); because they combust refinery-generated gases, they are potentially fuel gas combustion devices under NSPS Subpart J. The Equilon Consent Decree required PSR submit a Hydrocarbon Flaring Study to EPA which proposed ways to reduce the number and size of flaring events. The Equilon Consent Decree mandated that the proposed flaring reduction solution in the Hydrocarbon Flaring Study (i.e., flare gas recovery) be implemented by December 31, 2006. The flare gas recovery system was permitted under OAC 918 and was operating as of June 27, 2006.

As a result of the Hydrocarbon Flaring Study, PSR submitted a determination request in 2006 for two flare projects as to whether either triggered NSPS Subpart J. EPA determined that the project in 1983 when PSR added three vent streams from the Delayed Coker Unit to the common flare header triggered NSPS Subpart J. PSR accepted NSPS Subpart J applicability to the three flares and committed to demonstrating compliance using a flare gas recovery system by December 31, 2012.

On December 22, 2008, the Federal Register published a notice of a stay to provisions of 40 CFR 60 Subpart Ja relating to the definition of flares, modifications to flares, and the $NO_X$ limit for combustion devices. On September 12, 2012, EPA published a Federal Register notice that lifted the stay and amended certain provisions of Subpart Ja that were included in the stay. With the lifting of the stay and the modification definition for flares under 60.100a(c), PSR triggered NSPS Subpart Ja with the connection to the existing flare system in the Benzene Reduction Unit, which started up on April 5, 2011 (permitted under OAC 1045).

**Alternative Monitoring Plans:** PSR has requested alternative monitoring plans (AMP) from EPA for the following equipment/systems subject to NSPS monitoring requirements:

- Tank Truck Loading Rack (12/04/01) – NSPS Subparts A and J: Meet sulfur product specifications for all fuels loaded, in lieu of $SO_2$ emission monitoring at the vapor combustor.
- Fuel Gas Merichem Caustic Regeneration System (08/21/02) - NSPS Subparts A and J: Monitor $H_2S$ in overhead of the caustic regeneration oxidation tower less frequently, using operating parameters to correlate with H2S concentration, due to inherently low $H_2S$, in lieu of installing a continuous emission monitor. This AMP became invalid upon construction and operation of a Wet Gas Scrubber at the FCCU in 2006.
- FCCU WGS:
    - Monitoring in lieu of COMs (8/3/05) – 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. PSR 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 install 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 August 3, 2005, with excess opacity emissions for both 40 CFR 60 Subpart J and 40 CFR 63 Subpart UUU based on a 3-hour rolling basis.
    - Monitoring in lieu of COMs (12/28/07) – NSPS Subparts A and J; NESHAP Subparts A and UUU: revised the approval issued 8/3/05 to determine liquid flow rate using a continuous flow meter.
    - Monitoring in lieu of COMs (09/09/19) – NSPS Subparts A and J; NESHAP Subparts A and UUU: renewed the approval issued 12/28/07 after reevaluating the approval and determining it is adequate to assure compliance with the lower visible emission limit at the FCCU in amended Subpart UUU.

- Flare:
  - Total Sulfur (03/22/11) – NSPS Subparts A and J: Install, calibrate, maintain and operate a total sulfur continuous monitoring system, instead of a $H_2S$ continuous monitoring system; and use sulfur data collected from the east flare to represent the sulfur content at the north and south flares.
  - $H_2S$ (08/21/12) - NSPS Subparts A and J: Remove the provisions in the Flare Total Sulfur AMP that require continuous monitoring of total sulfur in the east flare and comply with continuous $H_2S$ monitoring instead, but continue to use monitoring data collected from the east flare to represent the $H_2S$ content at the north and south flares.
  - J to Ja (01/20/14) – NSPS Subparts A and Ja: Removed reference to Subpart J, replacing all references to Subpart Ja, which PSR triggered due to modification of the flare April 2011 by the addition of the benzene reduction unit (BRU).

### 2.1.2 40 CFR 63 Subpart CC - Petroleum Refineries & Overlap with Parts 60, 61, and NWCAA Regulations

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 PSR is comprised of all the emission points in combination listed below:

- MPVs
- Storage vessels
- 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. Then followed amendments 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 PSR:

- Addition of delayed coking unit (DCU) decoking operation standards
- 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 atmosphere and PRD routed to a closed vent system
- Revision of the definition of Group 1 miscellaneous process vents (MPVs); none of PSR’s in situ sampling systems triggered the Group 1 threshold
- 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; no changes needed at PSR to comply.

With this second renewal of the AOP, changes resulting from amendments to Refinery MACT 1 have been incorporated.

Equipment exempt from being part of 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 with all by complying with only the most stringent standard. Following is an applicability discussion for process units or emission points at PSR subject to 40 CFR 63 Subpart CC. In addition, if the emission units/process is 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 2-5: 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 |

**Delayed Coking Unit Coke Drum Venting:** For the DCU, there are no other existing regulations governing decoking operations. After January 30, 2019, Refinery MACT 1 requires DCUs to depressure coke drums to a closed blowdown system until the average vessel pressure or temperature meets applicable limits. PSR operates 2 coke drums, 15100A and 15100B. PSR complies by operating an interlock system that does not allow the coke drums to be opened to atmosphere until the pressure in the top of the drum meets 2.0 psig or less.

**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. PSR maintains the following Group 1 MPVs (feed surge drum vent 6D-C8 no longer used with shutdown of CRU1):

- VPS - Desalter Waterwash Surge Drum Vent (1A-C46)
- DCU - Coker Fractionator Overhead Accumulator Vent (15-C4)
- FCCU - Separator Bottoms Drum Vent (4B-C35)
- FCCU - 1st Stage Compressor in-line Separator Vent (4B-C102)
- CPU – Flare Knockout Drum Vent (5J-C56)

- CPU – Flare Knockout Drum Vent (5J-C85)
- CRU2 - Feed Surge Drum Vent (10F-104)
- CRU2 - Platformate Splitter Receiver Vent (10F-119)
- ALKY2 - Acid Vapor Caustic Scrubber Vent (12F-115)
- HTU2 - Fractionator Accumulator Vent (11F-209)

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). PSR evaluated these newly-defined MPVs and all were less than the Group 1 threshold.

All PSR 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. PSR 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 PSR complies by following standard operating procedures for any and 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 PSR 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.

Atmospheric PRDs in the refinery have been identified as follows:

- VPS Unit Atmospheric Tower (1A-C1): 11 PRDs
- FCCU Main Fractionator (3B-C1): 9 PRDs
- HTU1 Fractionator (7C-C5): 5 PRDs

**Flares:** Flares used as control devices for emission points subject to this subpart are regulated under Refinery MACT 1. As all (3) refinery flares are 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, PSR operates 17 sampling stations along the refinery's perimeter, a field blank and a duplicate sampler. Each sampler continuously pulls ambient air through a passive diffusive 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 Racks:** The gasoline loading rack at PSR is a Group 1 affected source under Refinery MACT 1 and is also subject to 40 CFR 60 Subpart XX Bulk Gasoline Terminals. Under the overlap provisions in §63.640(r), the gasoline loading rack is only required to comply with Refinery MACT 1, which mandates that subject racks comply with various referenced sections of 40 CFR 63 Subpart R; Subpart R then references various sections of Subpart XX.

**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). Because PSR's marine terminal is not subject to Subpart Y, 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. On June 20, 3013, the EPA published amendments. The regulation includes monitoring requirements with leak definitions and repair scheduling obligations for both closed-loop and once-through systems. PSR only has closed-loop systems so the once-through requirements were not addressed in the AOP.

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. Requirements for heat exchanges are listed in the AOP in Section 6, Commonly Referenced Requirements.

**Storage Vessels:** Storage vessels at an existing source may trigger applicability for 40 CFR 60 Subparts K, Ka, and Kb, and NWCAA Regulations, as well as 40 CFR 63 Subpart CC. A discussion of how storage vessels trigger applicability under these overlapping standards follows.

Storage vessels trigger applicability under the NSPS according to the following:

- 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).

Storage vessels 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 a:

- 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 m3 (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 2-3. For additional discussion, see the section under Wastewater.

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.

In addition to the federal requirements that apply to storage vessels, several NWCAA rules potentially apply to the refinery storage tanks. These programs include:

- NWCAA 560: Storage of Organic Liquid
- NWCAA 580.3: High Vapor Pressure Volatile Organic Compound Storage Tanks
- NWCAA 580.9: High Vapor Pressure Volatile Organic Compound Storage in External Floating Roof Tanks

Many of the requirements in NWCAA 560 and 580.3 do not have associated monitoring, recordkeeping, and reporting requirements; as such, monitoring requirements have been gap-filled into the AOP. Most of the gap-filled requirements parallel those required in the other applicable rules for the tank(s).

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 are found in the AOP.

The applicability of these programs vary 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 Table 2-6.

**Table 2-6: 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.

Several fixed roof storage tanks were constructed with the original refinery in 1958 but were subsequently fitted with floating roofs (i.e., Tanks 14, 15, 30, TK-15D-100A, TK-15D-100B, and TK-15D-100C). Pursuant to 40 CFR 60.14(e)(5), addition of control devices (such as floating roofs) are not considered modifications under NSPS; therefore, these tanks do not trigger requirements under those Subparts.

According to a letter from PSR dated October 13, 2004, PSR conducted a review pursuant to the Equilon Consent Decree and determined that Tanks 12, 13, 14, 60, 61, 61, 70, 71, 72, and 73 are subject to 40 CFR 60 Subpart Kb.

As discussed in SofB Section 3.4.2, the nonene product has the potential to contain one or more of the listed HAPs under Subpart CC. As such, the nonene storage tanks (Tank 80, 81, and 82) are subject to 40 CFR 63 Subpart CC Group 2 storage vessel requirements.

Table 2-7 lists the various storage vessels at PSR and identifies which regulatory programs are triggered for each tank or set of tanks. Shaded cells indicate where overlap provisions have dictated which federal tank program applies – Refinery MACT 1 or NSPS (K, Ka, Kb).

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. As part of the RSR Initiative, Refinery MACT 1 §63.660 requires compliance with 40 CFR 63 Subpart SS or Subpart WW. PSR submitted a Notification of Compliance Status stating they were in compliance with Tank Control Level 2 requirements in Subpart WW. The three most recently permitted storage tanks (503, 504 and 505) were all approved in OACs written after newer RTR Initiative changes went into effect. In the OACs (OAC 1291 for tank 503 and OAC 1301 for tanks 504 and 505), the nonbinding introductory language incorrectly identifies the tanks as subject to 40 CFR 63 Subpart WW, instead of 40 CFR 60 Subpart Kb. The tanks are actually subject to NSPS Kb and Refinery MACT 1. Under the overlap provisions in Refinery MACT 1, PSR complies with Refinery MACT 1, which requires compliance with 40 CFR 63 Subpart WW Tanks - Control Level 2.

Note that there are no overlap provisions specified for Group 1 Wastewater tanks.

Tables 1.13.2 and 1.14 in the AOP list the storage tanks at the refinery and the applicable regulations. Highlighting indicates which federal standard the refinery must comply with if overlap provisions apply. NWCAA 560 / 580 requirements and OAC requirements are unaffected by overlap provisions (so they apply, regardless).

**Table 2-7: Storage Vessel Control Requirement**

| Tank ID# | NSPS K | NSPS Ka | NSPS Kb | MACT CC (RMACT1) | NESHAP FF (BWN) | 560 / 580 (SIP) | OAC | Const/Mod Date |
|---|---|---|---|---|---|---|---|---|
| **External Floating Roof Tanks** | | | | | | | | |
| 4,5,6 | X | | | Group 1 | | X | | 1974 |
| 19 | X | | | Group 1 | | X | | 1973 |
| 38 | | | X | Group 1 | | X | 295a CO 08 | 1991 |
| 15 | | | VP too low | Group 2 | | VP too low | 262a | 1958 Mod 1990 |
| 503 | | | X | Group 1 | | X | 1291 | 2020 |
| 505 | | | X | Group 1 | | X | 1301 | TBD |
| 72,73 | | | X | Group 1 Waste Water | X | X | 345a | 1991 |
| 80,81,82 (MTVP < 0.75 psia) | | | VP too low | Group 2 (HAP) | | VP too low | 296a | 1990 |
| 1,2,3,11,17, 21,22,24,29,43,5 0,51,52,55,58 | | | | Group 1 | | X | | 1958 |
| 34,44,59 (MTVP < 0.75 psia) | | | | Group 2 | | | | 1958 |
| 45 (MTVP < 0.75 psia) | | | VP too low | Group 2 (HAP) | | VP too low | 297a | 1991 |
| **Internal Floating Roof Tanks** | | | | | | | | |

| Tank ID# | NSPS K | NSPS Ka | NSPS Kb | MACT CC (RMACT1) | NESHAP FF (BWN) | 560 / 580 (SIP) | OAC | Const/Mod Date |
|---|---|---|---|---|---|---|---|---|
| 36 | X | | | Group 1 | | X | | 1973 |
| 39 | | | X | Group 1 | | X | 337a | 1992 |
| 12,13 | | | X | Group 1 | | X | | 1958 |
| 14 | | | X | Group 1 | | X | | 1958 Mod 1978 |
| 85 (0.75 psia < MTVP < 1.5 psia) | | | X | Group 2 | | VP too low | 1046 | 2010 |
| 60 | | | X | Group 1 Waste Water | X | X | 341a | 1958 Mod 1991 |
| 61 | | | X | Group 1 Waste Water | X | X | | 1958 |
| 62 | | | X | Group 1 Waste Water | X | X | | 1958 Mod 1990 |
| 70 | | | X | Group 1 Waste Water | X | X | 241a | 1988 |
| 71 | | | X | Group 1 Waste Water | X | X | 316a | 1990 |
| 23,28,53,54 | | | | Group 1 | | X | | 1958 |
| 30 | | | | Group 1 | | X | | 1958 Mod 1995 |
| TK-15D-100A, TK-15D-100B, TK-15D-100C (MTVP < 0.75 psia) | | | VP too low | Group 2 | | VP too low | | 1958 Mod 1985 |
| **Fixed Roof Tanks** | | | | | | | | |
| 18 | | VP too low | | Group 2 | | | | 1980 |
| 37 | | VP too low | | Group 2 | | | | 1981 |
| 504 | | | VP too low | Group 2 | | VP too low | 1301 | TBD |
| 10,16,25,26,27,31,32,33,35,40,41,42,49,56,57,204 | | | | Group 2 | | | | 1958 |

**Wastewater:** PSR has more than a thousand wastewater streams and treatment operations spread throughout the process units around the refinery. These streams may be subject to federal standards regulating VOC emissions under 40 CFR 60 Subpart QQQ, as well as benzene under 40 CFR 61 Subpart FF and/or Refinery MACT 1.

Following is an explanation of the applicability for each of the federal wastewater requirements at the refinery.

40 CFR 60 Subpart QQQ (NSPS QQQ) applies to VOC emissions from refinery wastewater systems that were constructed, modified, or reconstructed after May 4, 1987. Wastewater systems under NSPS QQQ include:

- Individual drain systems,
- Oil-water separators, and
- Aggregate facilities

Excluded from the requirements of NSPS QQQ are:

- stormwater sewer systems,
- ancillary equipment physically separate from the wastewater system and does not contact with, or store, oily wastewater, and
- non-contact cooling water systems.

The refinery has added or modified individual drain systems at a number of process units after May 4, 1987. The following units have triggered NSPS QQQ for process drains at the refinery:

- VPS
- DCU
- FCCU
- Nonene Unit
- HTU2
- HTU3
- ISOM
- BRU
- Diesel Railcar Loading Rack
- Nonene Truck and Railcar Loading Rack,
- Feedstock Imports Rail Unloading Facility
- Flare Gas Recovery (FGR),
- Refinery Laboratory, and
- Tanks 503, 504, and 505

40 CFR 63 Subpart CC regulates refinery wastewater streams and treatment operations that emit, contact or have equipment that contact one or more of the HAPs listed in 40 CFR 63 Subpart CC. Benzene is the triggering HAP at the refinery.

Wastewater streams and treatment operations subject to Refinery MACT 1 include:

- Oily Water Sewer System
- Individual Drain Systems
- Storage vessels
- Oil-water separators
- Other Ancillary equipment

Under Refinery MACT 1, wastewater streams are divided into Group 1 and Group 2. A Group 1 wastewater stream has:

- a refinery-wide total annual benzene (TAB) loading of 10 megagrams (Mg) per year or greater,
- 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 part 61 Subpart FF.

A Group 2 wastewater stream is a wastewater stream that does not meet the definition of Group 1 wastewater stream.

40 CFR 61 Subpart FF, commonly referred to as the benzene waste operations NESHAP (BWON), applies to benzene waste operations at petroleum refineries with more than 10 Mg per year of benzene in their waste streams. Yearly total annual benzene (TAB) analysis which identifies the total annual quantity of benzene entering the refinery wastewater collection system for both the controlled and uncontrolled streams is greater than 10 Mg/yr.

PSR was required to come into compliance with BWON in 1991 for treatment, storage, and disposal of benzene-containing hazardous waste at the refinery. Every process unit at PSR has wastewater and treatment operations regulated under BWON.

BWON contains control requirements, limits, and work practice standards for equipment that handle and treat benzene-containing waste, including:

- Tanks
- Surface impoundments
- Containers
- Individual drain systems
- Oil-water separators
- Treatment processes
- Closed vent systems and control devices

The purpose of this regulation is to reduce the amount of benzene emissions to the atmosphere from wastewater operations.

Regulatory Overlap: Through an overlap provision in the Refinery MACT 1, wastewater programs are consolidated to require compliance with the most stringent (usually) requirements. Wastewater streams subject to both NSPS QQQ and Refinery MACT 1, under the overlap provisions in §63.640(o), are required to do the following:

- Any Group 1 wastewater streams managed in a piece of equipment that is also subject to 40 CFR 60 Subpart QQQ, is required only to comply with Subpart CC, which references the NESHAP for Benzene Waste Operations (BWON) under 40 CFR 61 Subpart FF.
- For Group 2 streams, the refinery is required to comply with both Subpart CC and Subpart QQQ.

Requirements for wastewater streams under Refinery MACT 1 reference requirements in 40 CFR 61 Subpart FF.

Effluent Plant and Sewer System (ETPPDF**)**: The refinery triggered NSPS QQQ for the oil-water separator, dissolved air floatation (DAF) unit 3, at the effluent plant constructed in 1994 under OAC 514. DAF3 manages a Group 1 wastewater stream subject to Refinery MACT 1; as such, DAF3 is only required to comply with Refinery MACT 1, which references BWON requirements.

In the AOP, Section 1 Emission Unit Identification only identifies process drains subject to NSPS QQQ and BWON at individual process units, however not all drains at the process unit are necessarily subject to, or required to be, controlled under NSPS QQQ or BWON. Requirements for drains in process units across the refinery that are subject to Refinery MACT 1 are collectively addressed under the Effluent Plant and Sewer System (ETPPDF). It is the refinery's responsibility to track applicability and control requirements for each drain (i.e., BWON, NSPS QQQ, Refinery MACT 1).

In the AOP requirement tables in Section 5, drains listed for each process unit which are subject to Subpart QQQ are referred to AOP Section 6.4 for compliance requirements; requirements for wastewater streams regulated under 40 CFR 63 Subpart CC are addressed separately under the Effluent Plant requirements contained in AOP Section 5.13.

Effluent Plant Storage Tanks: According to the definition of storage vessel under Refinery MACT 1, wastewater tanks are not considered storage tanks; they must comply with the Refinery MACT 1 wastewater provisions which reference requirements in BWON. As such, the overlap provisions for Refinery MACT 1 and NSPS tank requirements (i.e., Subparts K, Ka, and Kb) for storage vessels do not apply to wastewater tanks. Therefore, Effluent Plant storage tanks are also potentially subject to NSPS tank requirements (i.e., 40 CFR 60 Subparts K, Ka, and Kb) and 40 CFR 61 Subpart FF. Note Subpart FF includes an alternative standard for tanks that references Subpart Kb requirements.

NWCAA 560 and 580.3 potentially apply to the Effluent Plant storage tanks that store organic liquids with a vapor greater than 1.5 psia. Similarly to Subpart Kb, it is conservatively assumed that NWCAA 560 and 580.3 apply to each Effluent Plant storage tank because of the variability in the contents and vapor pressures.

Many of the requirements in NWCAA 560 and 580.3 do not have associated monitoring, recordkeeping, and reporting requirements; as such, these have been gap-filled into the AOP. Most of the gap-filled requirements parallel those required in the other applicable rules.

**Equipment Leaks (LDAR):** 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. This work practice standard is referred to as a leak detection and repair (LDAR) program.

Equipment leaks at an existing major source may be subject to equipment leak requirements under 40 CFR 63 Subpart CC. They may also be subject to equipment leaks of VOC provisions found in new source performance standards in 40 CFR 60 Subparts VV/VVa or GGG/GGGa due to date of construction or modification of a process unit. For any particular process unit, there may be more than one LDAR standard that applies. A discussion of how equipment leaks trigger applicability under these overlapping standards follows.

40 CFR 60 Subpart VV applies to equipment leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) units constructed, modified, or reconstructed after January 5, 1981 and on or before November 7, 2006. 40 CFR 60 Subpart VVa applies to equipment leaks of VOC in the SOCMI units constructed, modified, or reconstructed after November 7, 2006.

SOCMI units, for the purposes of Subparts VV/VVa, are those that produce, as intermediates or final products, one or more of the chemicals listed in 40 CFR 60.489, including nonene. As such, the Nonene Unit qualifies as a SOCMI unit for the purposes of NSPS and is directly subject to Subpart VV based on date of construction (1991). Pursuant to 40 CFR 60 Subparts GGG and GGGa, those units subject to VV are excluded from Subparts GGG and GGGa. So, LDAR at the Nonene Unit is required in accordance with 40 CFR 60 Subpart VV only.

Note that the definition of "process unit" under 40 CFR 60 Subparts VV (6/2/08), GGG (11/16/07), and GGGa (11/16/07) is currently stayed. Each regulation includes identical language. For example, Subpart GGG (60.590(e)), states:

> *Stay of standards.* Owners or operators are not required to comply with the definition of "process unit" in §60.590 of this subpart until the EPA takes final action to require compliance and publishes a document in the Federal Register. While the definition of "process unit" is stayed, owners or operators should use the following definition:
>
> *Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

The definition of process unit that is stayed is:

> *Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Essentially, since the new definition is stayed, the rule reverts to the older definition. As such, under the older definition, equipment not explicitly part of a production unit, such as storage tanks and loading racks, are currently not subject to the LDAR requirements under 40 CFR 60 Subparts VV, GGG, and GGGa. Therefore, the Nonene Truck and Railcar Loading Rack are not part of a process unit and are not subject to LDAR requirements under NSPS VV.

There are no process units at the refinery that directly trigger 40 CFR 60 Subpart VVa. However, LDAR standards triggered for 40 CFR GGGa at the CRU1 and BRU require compliance with 40 CFR 60 Subparts VVa, and therefore, these provisions are referenced in AOP citations.

40 CFR 60 Subparts VV and VVa specify monitoring and recordkeeping requirements associated with leaks from various process equipment including compressors, pumps in light liquid service, pressure relief devices in gas/vapor service, sampling connections, open-ended valves and lines, valves in gas/vapor and light liquid service, pumps and valves in heavy liquid service, pressure relief devices in heavy liquid and light liquid service, flanges, and other connections. Note that under Subpart VVa, the standards applicable to connectors in gas/vapor service and light liquid service (40 CFR 60.482-11a) were stayed on June 2, 2008 (73 FR 31376). Instrument monitoring is conducted using EPA Method 21 at a frequency that is specified for each type of process equipment affected by the rule.

If a leak is measured in accordance with EPA Method 21, a first attempt at repair is required within 5 days and the repair must be complete within 15 days, unless a delay of a repair is exercised. If a delay of repair in exercised, the repair must be technically infeasible within the 15-day repair period, or because the repair would potentially increase the size of the leak. In many circumstances, delays can be allowed until the affected process unit is shut down for maintenance.

Several other regulations also impose LDAR requirements at the refinery. 40 CFR 60 Subparts GGG applies to equipment leaks of VOC at petroleum refineries that were constructed, modified or reconstructed after January 4, 1983 but before November 7, 2006. 40 CFR 60 Subpart GGGa applies to equipment leaks of VOC at petroleum refineries constructed, modified, or reconstructed after November 7, 2006 The rules provide an applicability exception under 60.590a(d): those process units already subject to Subpart GGG and modified after November 7, 2006, remain subject only to Subpart GGG.

Subpart GGG and Subpart GGGa rely on the leak detection and repair (LDAR) standards of 40 CFR 60 Subpart VV and Subpart VVa, respectively. See the prior discussion for a description of the requirements of a Subpart VV/VVa LDAR program.

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 sources of HAPs that contain or contact one or more of the listed HAPs at or above 5 wt%. Refinery MACT 1 requires a LDAR program conducted in accordance with 40 CFR 60 Subpart VV. Note that compressors in hydrogen service are explicitly exempted from the monitoring requirements.

Pursuant to 40 CFR 63.640(p), equipment leaks subject to 40 CFR 63 Subpart CC along with provisions under 40 CFR 60 and 61 that were promulgated prior to September 4, 2007 (40 CFR 60 Subparts VV and GGG) must comply with Subpart CC. Equipment leaks that are subject to both Subpart CC and Subpart GGGa must comply with Subpart GGGa, except that pressure relief devices in organic HAP service must only comply with §63.648(j).

Subpart CC (63.640(q)) also provides an overlap provision that allows the refinery to apply a consistent LDAR program within a particular process unit:

> For overlap of subpart CC with local or State regulations, the permitting authority for the affected source may allow consolidation of the monitoring, recordkeeping, and reporting requirements under this subpart with the monitoring, recordkeeping, and reporting requirements under other applicable requirements in 40 CFR parts 60, 61, or 63, and in any 40 CFR part 52 approved State implementation plan provided the implementation plan allows for approval of alternative monitoring, reporting, or recordkeeping requirements and provided that the permit contains an equivalent degree of compliance and control.

NWCAA 580.8 requires an 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 alkylation (ALKY1 & ALKY2), polymerization (CPU), and LPG loading. However, in the federally-enforceable version of the regulation that is included in the State Implementation Plan (SIP) (December 13, 1989), the affected process units include alkylation, polymerization, and light ends units, so the only potentially subject units at PSR are the ALKY1, ALKY2, CPU, and the associated dedicated loading.

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, ALKY1 and ALKY2 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) and for those that are not subject to other federal rules are dated with both the date of the SIP version as federally enforceable and the date of the current rule (i.e., March 13, 1997) as state only.

In addition, for those units subject to the LDAR requirements under 580.8, the AOP also calls out one item because it is considered to be 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.

The Equilon Consent Decree required enhanced LDAR programs throughout the refinery for existing equipment as of the date of lodging (March 21, 2001). The Consent Decree required the refinery to implement an "enhanced" LDAR program that was more stringent than the requirements of Subpart VV, including leak definitions of 500 ppm and 2,000 ppm for valves and pumps, respectively, and was generally as stringent as the other potentially applicable programs. As such, PSR had chosen to comply with the Consent Decree LDAR requirements at all process units throughout the refinery, regardless of direct applicability, as the most stringent program. With termination of the Equilon Consent Decree on May 5, 2016, PSR may resume a LDAR program conducted in accordance with the applicable requirements specific to each process unit.

Should PSR continue to implement an enhanced LDAR program across the entire refinery, the only process units legally subject to the enhanced LDAR program requirements (e.g., lower leak definitions) are units that have triggered 40 CFR 60 Subpart GGGa directly, or those with enhanced LDAR required as a condition of the OAC under BACT. The CRU1 and BRU have triggered lower leak definitions directly under 40 CFR 60 Subpart GGGa. Equipment components at units with lower leak definitions required under minor NSR permits as a condition of BACT are found at HTU2, HTU3, BHU, ISOM, Alk1, FGR and VPS. For these units with lower leak definitions, NWCAA has gap-filled monitoring that requires specific Method 21 calibration requirements for units complying with lower leak definition using NWCAA's sufficiency monitoring authority.

Table 2-8 presents a list of process units at PSR and LDAR program applicability.

**Table 2-8: LDAR Program Regulatory Applicability**

| Process Unit | GGG | GGGa | CC | VV | OAC (enhanced) | NWCAA 580.8 | Notes |
|---|---|---|---|---|---|---|---|
| VPS | X | | X | | 1253 | | |
| DCU | X | | X | | | | |
| FCCU | X | | X | | | | |
| CPU | X | | | | | X | |
| Nonene Unit | | | | X | | | SOCMI unit |
| CRU1 | | X | X | | | | |
| CRU2 | | | X | | | | |
| Alky1 | X | | X | | 887a | X | |
| Alky2 | | | X | | | X | |
| BHU | X | | X | | 772b | | |
| HTU1 | | | X | | | | |
| HTU2 | X | | X | | 630c | | |
| HTU3 | X | | X | | 787h | | |
| Isom | X | | X | | 883b | | |
| Benzene Reduction Unit | | X | X | | 1045[b] | | |
| SRU | X | | X | | | | |
| Cogen | | | | | | | No LDAR |
| Gasoline/Diesel Truck Loading[a] | | | X | | | | |
| Diesel Railcar Loading[a] | | | | | | | No LDAR |

| Process Unit | GGG | GGGa | CC | VV | OAC (enhanced) | NWCAA 580.8 | Notes |
|---|---|---|---|---|---|---|---|
| Nonene Loading[a] | | | | | | | No LDAR |
| Ethanol Unloading & Storage[a] | | | | | | | No LDAR |
| Dock | | | | | | | No LDAR |
| LPG Loading | | | | | | X | |
| Flares | | | X | | | | |
| FGR | X | | X | | 918b | | |
| Tank Farm | | | X | | | | |

[a] As discussed above, due to the stay of the "process unit" definition, storage tanks and loading racks are currently not subject to the LDAR requirements in 40 CFR 60 Subparts VV, GGG, and GGGa.
[b] The OACs do not include enhanced LDAR requirements because the units were already subject to Subpart GGGa.

### 2.1.3 40 CFR 63 Subpart UUU - Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

40 CFR 63 Subpart UUU (commonly referred to as Refinery MACT 2) was promulgated on April 11, 2002. Refinery MACT 2 applies to petroleum refineries located at a major source and establishes emission standards and requires compliance with emission limitations and work practice standards. Refinery MACT 2 applies to new, reconstructed or existing affected sources at a refinery and includes:

- Process vents or groups of process vents:
  - On FCCUs associated with regeneration of the catalyst (i.e., catalyst regeneration flue gas vented through CO Boilers)
  - On Catalytic reforming unit (CRUs) associated with regeneration of the catalyst, including vents used during:
    - Unit depressurization
    - Purging
    - Coke burn
    - Catalyst rejuvenation
  - SRUs or tail gas treatment unit (TGTU) serving SRUs
- Bypass lines serving new, existing, or reconstructed:
  - CCUs,
  - CRUs, or
  - SRUs.

Note that PSR does not operate any bypass lines on either their FCCU or CRUs. They do, however, operate bypass lines at the SRUs. These bypass lines are used during unit shutdowns to divert effluent from the Claus section of the SRU around the SCOT tailgas treatment units, directly to the incinerators. Because these bypass lines do not divert the affected vent streams away from the control devices (incinerators) used to comply with the requirements of this subpart, the bypass lines are not part of the affected source.

Refinery MACT 2 was amended under the RTR initiative on December 1, 2015. Then followed amendments 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 amendments to Refinery MACT 2 resulted in the following changes to the affected source at PSR:

- 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
- Requirement to conduct periodic performance tests for particulate matter and one-time performance test for hydrogen cyanide (HCN) at FCCUs
- Requirement to install a continuous opacity monitoring system (COMS) on FCCU exhaust
- Establishment of emission limitations during purging operations for CRUs

With this second 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, PSR 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 HAP and organic HAP 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 PSR's FCCU are controlled using a wet scrubber. PSR follows an alternate monitoring plan (AMP) approved by EPA, renewed September 9, 2019. 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 emission 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 each existing semi-regenerative CRU during coke burn-off and catalyst rejuvenation are limited by reducing the uncontrolled emissions of HCl to a concentration of no more than 30 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 emission 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.

PSR operates oxygen-enriched SRUs, therefore, after the RTR Initiative revisions, PSR choose to comply, as allowed under NSPS Subpart J 60.100(e), with the provisions in NSPS Subpart Ja for $SO_2$ emission limitations, determined using Equation 1 of §60.102a(f)(1)(i). To demonstrate compliance with the oxygen-enriched limit, PSR was required to install and operate a continuous monitoring system to measure and record hourly average $SO_2$ concentration (dry basis) at 0% excess air for each exhaust stack, including an oxygen monitor for correcting the data for excess air. They were also required to install and operate either a continuous emission monitoring system to measure and record the oxygen concentration for the inlet air/oxygen supplied to the system, or a CPMS to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.

**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 SRU during startup and shutdown to reflect changes following the RTR initiative. Note: no updates were required to the OMMP for the CRUs. The OMMP revisions addressed operation of continuous parameter monitoring systems (CPMS) during startup and shutdown. Updates to these plans were received March 23, 2018 and approved by NWCAA August 18, 2018.

Equipment that Refinery MACT 2 does not apply to:

- Thermal catalytic cracking units,
- SRU that does 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:** Shell has requested alternative monitoring plans (AMP) from EPA for the following equipment/systems subject to NESHAP monitoring requirements:

FCCU WGS:

- Monitoring in lieu of COMs (8/3/05) – 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 Shell 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 August 3, 2005, with excess opacity emissions for both 40 CFR 60 Subpart J and 40 CFR 63 Subpart UUU based on a 3-hour rolling basis.

- Monitoring in lieu of COMs (12/28/07) – NSPS Subparts A and J; NESHAP Subparts A and UUU: revised the approval issued 8/3/05 to determine liquid flow rate using a continuous flow meter.
- Monitoring in lieu of COMs (09/09/19) – NSPS Subparts A and J; NESHAP Subparts A and UUU: renewed the approval issued 12/28/07 after reevaluating the approval and determining it is adequate to assure compliance with the lower visible emission limit at the FCCU in amended Subpart UUU.

## 2.2 Other General and Equipment-Specific Applicable Requirements

PSR is also subject to a number of non-refinery-related federal standards under 40 CFR Part 60 and 40 CFR Parts 61 and 63.

### 2.2.1 General Provisions

**40 CFR 60 Subpart A:** When an NSPS applies to a facility, the General Provisions of 40 CFR 60 Subpart A also apply, unless otherwise specified in the subpart. Requirements from Subpart A included in AOP Section 3 are those that are applicable when triggered by a particular action. If the Subpart A term is not a specific requirement for the facility, it is not included in the AOP. If the requirement was something that was a one-time requirement that has been completed, it is not in the AOP.

**40 CFR 61 Subpart A:** When a Part 61 NESHAP applies to a facility, the general provisions of 40 CFR 61 Subpart A also apply. These general provisions are included in AOP Section 3. Subpart A requirements tend to be applicable only when triggered by a particular action, such as an initial startup notice and an initial notification when a facility becomes subject to a standard under 40 CFR 61.

**40 CFR 63 Subpart A:** As a major source of Hazardous Air Pollutants (HAPs), PSR owns and operates specific affected equipment regulated under the following NESHAP/MACT Subparts. When a NESHAP applies to a facility, the General Provisions of the associated 40 CFR 61 or 63 Subpart A also apply, unless otherwise specified in the subpart. If a Subpart A requirement is applicable when triggered by a particular action, it is found in AOP Section 3. Conversely, if a part of Subpart A does not have specific requirements for the facility, it is not included in the AOP. If the requirement was something in the past that was a one-time requirement that has been completed, it is also not in the AOP.

### 2.2.2 Boilers, Process Heaters & Fossil Fuel-Fired SGU Standards

**40 CFR 63 Subpart DDDDD - 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), and is commonly referred to as the Boiler MACT. Boiler MACT was revised November 20, 2015, however, the revisions do not affect the requirements that apply at PSR.

PSR submitted Initial Notification under 40 CFR 63.7545(b), received by NWCAA May 31, 2013, listing all subject units at the refinery: all units have a heat input capacity greater than 10 MMBtu/hour, fire refinery fuel gas and natural gas, and commenced construction prior to June 4, 2010 (i.e., are considered existing units). The list included 18 gas-fired process heaters at the refinery and the Erie City Boiler (see Table 2-9). With shutdown of the (3) heaters at CRU1, the refinery now has 15-gas fired processes heaters.

The list did not include the CO Boilers at the FCCU and the heat recovery steam generating (HRSG) at the Cogens. The CO Boilers qualify as boilers under Boiler MACT; however, they are also subject to 40 CFR 63 Subpart UUU. In accordance with §63.7491(h), these units are not subject to Boiler MACT. Heat recovery steam generating (HRSG) units at the Cogens are considered waste heat boilers under the Boiler MACT; however, waste heat boilers are excluded from the definition of “boiler” as affected sources under the Boiler MACT. Therefore, the Cogen HRSGs are not subject to Boiler MACT.

All the subject process heaters and boilers fall within the “units designed to burn gas 1 fuels” subcategory. Boiler MACT does not require any pollutant-specific emission limits for existing or new heaters and boilers in the gas 1 subcategory. Instead, the rule requires work practice standards that include periodic “tune-ups” and inspections, as described in 63.7540(a)(10).

Boiler MACT also identifies alternate work practices that apply instead of emission limitations, during periods of startup and shutdown. Because the boilers and process heaters at PSR are not subject to any Boiler MACT emission limitations, there are no alternate work practices that would apply during startup and shutdown. The work practice standards for units designed to burn gas 1 fuels are required at all times, therefore there are no AOP Terms for periods of startup or shutdown.

For units equipped with a continuous oxygen trim system, tune-ups are required once every five years; those without continuous oxygen trim systems must have tune-ups annually. The units equipped with a continuous oxygen trim system are listed in Table 2-9. An oxygen trim system, for the purposes of PSR, may control oxygen to either a setpoint or a set-range using either oxygen or carbon monoxide sensors. To influence the oxygen, the oxygen trim control system at PSR may manipulate the air supply directly or may adjust the fuel supply or the heater’s operation.

Initial tune-ups were performed at PSR over a period from November 4, 2015 through January 19, 2016. PSR intends to perform annual tune-ups for all units, even those operated with a continuous oxygen trim system (auto dampers).

Boiler MACT also required a one-time energy assessment performed by a qualified energy assessor as described in 40 CFR 63 Subpart DDDDD Table 3. PSR contracted with ERM to perform the energy assessment on June 15 & 16, 2015, with recommendations contained in final report dated January 25, 2016. As this one-time requirement has been met, all references to required energy assessment have been removed from the permit.

**Table 2-9: Boiler MACT Units**

| Unit | Rating (MMBtu/hr) | Unit | Name | Oxygen Trim Control |
|---|---|---|---|---|
| Erie City Boiler | 390 | BOHO | 31GF1 | Yes |
| Atmospheric Charge Heater | 415 Combined | VPS | 1A-F5 | Yes |
| Atmospheric Charge Heater | | | 1A-F6 | Yes |
| Gas Oil Tower Heater | 157 | VPS | 1A-F4 | Yes |
| Vacuum Charge Heater | 98 | VPS | 1A-F8 | Yes |
| Charge Heater | 124 | DCU | 15-F100 | Yes |
| Charge Heater | 240 Combined | HTU1 | 7CF4 | No |
| Fractionator Reboiler | | | 7CF5 | No |
| Charge Heater | 65 | HTU2 | 11H101 | Yes |
| $H_2S$ Stripper Reboiler | 241 Combined | HTU2 | 11H102 | Yes |
| Fractionator Reboiler | | | 11H103 | Yes |
| Charge Heater | 205 Combined | CRU2 | 10H101 | Yes |
| Interheater 1 | | | 10H102 | Yes |
| Interheater 2 | | | 10H103 | No |
| Stabilizer Reboiler | 70 | CRU2 | 10H104 | No |
| CDHDS Heater | 80 | HTU3 | 60F201 | Yes |

**40 CFR 60 Subpart D, Da and Db – Fossil-Fuel Fired Steam Generating Units:** NSPS Subparts D, Da, and Db apply to fossil-fuel-fired steam generating units of a specified size and construction date.

The Erie City Boiler is a fossil-fuel-fired steam generating unit. However, it was constructed prior to August 17, 1971 (i.e., 1958) and has not been modified since; as such, it is not subject to 40 CFR 60 Subparts D, Da, or Db.

The CO Boilers are fossil-fuel fired steam generating units. CO Boiler 1 was constructed in 1958 and CO Boiler 2 was constructed in 1972; neither have been modified under NSPS. The combined maximum firing rate is 65 MMBtu/hr in full combustion mode, 30.4 MMBtu/hr in partial combustion mode. Supplemental gas firing rate is 262 MMBtu/hr for CO Boiler 1 and 133 MMBtu/hr for CO Boiler 2. These units are not subject to NSPS D (< 250 MMBtu/hr), NSPS Da (not an electric utility steam-generating unit), nor NSPS Db (not constructed after June 19, 1984).

Gas turbines are not affected sources under Subparts D, Da, or Db; however, the duct burners in the cogeneration units are potentially subject. The Cogens are equipped with supplemental firing burners located in the ducting at the beginning of the heat recovery steam generators (HRSGs). Each duct burner is rated at 163 MMBtu/hour, is capable of burning natural and/or refinery fuel gas, and was constructed in 1990/1991. As such, the duct burners are subject to 40 CFR 60 Subpart Db.

The duct burners are also subject to 40 CFR 60 Subpart J. As such, pursuant to Subpart Db (60.40b(c)), the duct burners are subject to the PM and $NO_X$ standards under NSPS Subpart Db and the $SO_2$ standards under NSPS Subpart J. However, because the burners do not burn coal, oil, wood, or municipal-type solid waste, in any quantity, they are not subject to the PM standards in NSPS Subpart Db.

### 2.2.3 Stationary Gas Combustion Turbine Standards

**40 CFR 60 Subpart GG - Stationary Gas Turbines:** NSPS Subpart GG applies to stationary gas turbines with a peak load heat input of 10 MMBtu/hr or greater (LHV) constructed, modified, or reconstructed after October 3, 1977. The Cogens each have a heat input rating of 450 MMBtu/hr and were constructed in 1990/1991. As such, they are subject to NSPS Subpart GG. Additional discussion of NSPS Subpart GG applicability to the Cogens can be found in SofB Section 3.9.1.

**40 CFR 63 Subpart YYYY - Stationary Combustion Engines:** When the Cogens were a stand-alone facility, they were an area source of HAP; however, when (Shell) PSR took ownership of the Cogens, they became part of a major source of HAP and potentially subject to 40 CFR 63 Subpart YYYY. However, the Cogens are still considered existing units since a change in ownership does not change the existing status of the turbines (63.6090(a)(1)). According to 63.6090(b)(4), "[e]xisting stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification." As such, 40 CFR 63 Subpart YYYY applies to the Cogens but there are no applicable requirements to be listed in the AOP.

### 2.2.4 Combustion Engines

**40 CFR 60 Subpart IIII - Stationary Compression Ignition Internal Combustion Engines:** 40 CFR 60 Subpart IIII applies to stationary compression ignition internal combustion engines (ICE) that commenced construction after July 11, 2005 and were manufactured after, for engines that are not fire pump engines, April 1, 2006 and, for fire pump engines, July 1, 2006. All refinery internal combustion engines burn diesel fuel and rely on the heat of compression for ignition. But three engines, the Main Control Room Emergency Generator, the Radio Tower Emergency Generator, and the EP Outfall Pump Engine were constructed after July 11, 2005 and manufactured after April 1, 2006. As such, the Main Control Room Emergency Generator, the Radio Tower Emergency Generator, and the EP Outfall Pump Engine are subject to 40 CFR 60 Subpart IIII.

Minor changes were made to NSPS IIII on July 7, 2016 and November 13, 2019. The AOP conditions have been update to reflect any changes.

Generally, 40 CFR 60 Subpart IIII requires that the engines meet specified EPA Tier emissions standards and burn only ultralow sulfur diesel with a sulfur content equal to or less than 15 ppmw.

*Stationary Compression Ignition ICE Emergency Service*

40 CFR 60 Subpart IIII specifically describes what it means to be in emergency service. Pursuant to 40 CFR 60.4211(f) to be considered an emergency stationary ICE, the engine must meet the following operational requirements:

- There is no time limit on the use of emergency stationary ICE in emergency situations.
- The emergency stationary ICE may be operated for a maximum of 100 hours per calendar year for the purposes of maintenance checks, readiness testing, emergency demand response, and voltage or frequency deviation support. Any operation for non-emergency situations allowed as described in the next bullet counts as part of the 100 hours per calendar year.
- The emergency stationary ICE may be operated for 50 hours per year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response. Except under specific circumstances, the 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility

to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described above is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine and will need to meet all the requirements for non-emergency engines.

None of the refinery emergency generators are used, or are contractually obligated to be available for, more than 15 hours per calendar year for emergency demand response as described in 63.6640(f)(2)(ii) or voltage or frequency deviations of 5 percent or greater below standard voltage or frequency (63.6640(f)(2)(iii)). Should PSR choose to use the engines for either of these purposes, additional requirements will become applicable.

**40 CFR 63 Subpart ZZZZ – Reciprocating Internal Combustion Engines:** 40 CFR 63 Subpart ZZZZ applies to Reciprocating Internal Combustion Engines (RICE) located at area and major sources of HAP. Note that engine test cells/stands are not subject to Subpart ZZZZ. Table 2-10 describes the subject RICE at the refinery. Each stationary internal combustion engine at the refinery is also subject to 40 CFR 63 Subpart ZZZZ.

**Table 2-10: PSR Reciprocating Internal Combustion Engines & 40 CFR 63 Subpart ZZZZ Applicability**

| Unit | Location | Equipment ID | Year Installed | Fuel/Type | Emergency Service? | Rating (hp) |
|---|---|---|---|---|---|---|
| Emergency Generator for process units | Control Room 2 | 30LEG2 | 1993 | Diesel/CI | Yes | 230 |
| Emergency firewater pump | BOHO | 33PGE3 | 1972 | Diesel/CI | Yes | 227 |
| Firewater pump | BOHO | 33PGE14 | 1987 | Diesel/CI | Yes | 261 |
| Firewater pump | BOHO | 33PGE15 | 1987 | Diesel/CI | Yes | 261 |
| Stand-by Wharf Generator | RPS-Dock | 30LEG5 | 2002 | Diesel/CI | Yes | 755 |
| Main Control Room Emergency Generator | Main Control Room | 30LEG6 | 2008 | Diesel/CI | Yes | 237 |
| EP Outfall Pump | RPS-Effluent Plant | 9QG68 | 2013 | Diesel/CI | No | 500 |
| Radio Tower Emergency Generator | RPS | 30LEG7 | 2013 | Diesel/CI | Yes | 80 |

All but the Main Control Room Emergency Generator, EP Outfall Pump, and the Radio Tower Emergency Generator are considered existing emergency RICE under 40 CFR 63 Subpart ZZZZ. They are considered "existing" under the rule because each engine with a power rating equal to or less than 500 brake horse power (hp) was constructed on or before June 12, 2006, and each engine with a power rating greater than 500 hp was constructed on or before December 19, 2002. The physical properties and construction history are discussed in more detail for each RICE in the associated process unit description.

*RICE Emergency Service*

40 CFR 63 Subpart ZZZZ specifically describes what it means to be in emergency service. Pursuant to 40 CFR 63.6640(f)(2), to be considered an emergency RICE, the engine must meet the following operational requirements:

- There is no time limit on the use of emergency stationary RICE in emergency situations.

- The emergency stationary RICE may be operated for a maximum of 100 hours per calendar year for the purposes of maintenance checks, readiness testing, emergency demand response, and voltage or frequency deviation support. Any operation for non-emergency situations as allowed described in the next bullet counts as part of the 100 hours per calendar year.
- The emergency stationary RICE may be operated for an additional 50 hours per year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response. Except for under specific circumstances, the 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described above is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine and will need to meet all the requirements for non-emergency engines.

None of the refinery emergency generators are used, or are contractually obligated to be available for, more than 15 hours per calendar year for emergency demand response as described in 60.4211(f)(2)(ii) or voltage or frequency deviations of 5 percent or greater below standard voltage or frequency (60.4211(f)(2)(iii)). Should PSR choose to use the engines for either of these purposes, additional requirements will become applicable.

### 2.2.5 40 CFR 63 Subpart PPPPP – 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. PSR maintains five octane test engines in the refinery lab for fuel testing, which qualifies as an engine test cell/stand. The test engines were installed prior to May 14, 2002; therefore, it is considered an existing engine test cell/stand. In 2016, the engine test cells/stands were relocated when the refinery laboratory was rebuilt. According to §63.2, construction of an affected source does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location, therefore, the relocated engine test cells/stands continue to be considered existing sources. Pursuant to 40 CFR 63.9290(b), existing sources are subject to Subpart PPPPP, but do not have to meet any of the requirements of Subpart PPPPP or the requirements of 40 CFR 63 Subpart A.

### 2.2.6 40 CFR 60 Subpart XX - Bulk Gasoline Terminals

NSPS Subpart XX applies to Bulk Gasoline Terminals constructed or modified after December 17, 1980. The gasoline loading rack at the refinery was modified in 1993 and triggered NSPS Subpart XX. However, it is also an affected source under the Refinery MACT 1 (i.e., 40 CFR 63 Subpart CC); therefore, according to the overlap provisions under Subpart CC (40 CFR 63.640(r)), those loading terminals that are subject to both NSPS Subpart XX and Refinery MACT 1 need only comply with the Refinery MACT 1 requirements.

### 2.2.7 40 CFR 63 Subpart Y - Marine Tank Vessel Loading Operations

40 CFR 63 Subpart Y applies to marine tank vessel loading operations that are major sources of HAP. However, existing offshore loading terminals (i.e., a location that has at least one loading berth that is 0.5 miles or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore) are subject to Subpart Y but are exempt from the Subpart Y requirements except that they must meet the submerged fill requirements under 46 CFR 153.282. PSR’s marine terminal is 0.5 miles from shore or more; therefore, it is subject only to the submerged fill requirements.

### 2.2.8 40 CFR 63 Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants: Site Remediation

40 CFR 63 Subpart GGGGG applies to the emissions of hazardous air pollutants (HAPs) at facilities where remediation activities are used to clean up spills and contaminated soil. PSR does infrequently conduct site remediation projects to, for instance, clean up after a leaking storage tank. However, because the total HAP quantity in remediation materials for the year is less than 1 Mg refinery-wide or the remediation is completed in no more than 30 consecutive calendar days, the refinery is only subject to recordkeeping requirements, which in accordance with §63.7881(c)(3), must be included in the Title V permit. This recordkeeping requirement is found in AOP Section 4 because it is a generally applicable requirement that applies refinery-wide.

### 2.2.9 NWCAA Section 508 – Spray Coating Operations

NWCAA Section 508 applies to spray coating operations at sources within NWCAA's jurisdiction. It establishes a program of work practice standards and controls for spray coating operations to reduce particulate matter emissions from coating overspray, lessen public exposure to toxic air pollutants, decrease emissions of precursors to the formation of tropospheric ozone and encourage pollution prevention. NWCAA' spray coating regulation does not apply to spray application of architectural or maintenance coatings on stationary structures.

PSR operates two small cabinet booths and one larger enclosed spray area, as follows:

- Small booth at I&E Shop (filter on vent)
- Small booth at Machine Shop (no filter)
- 3-sided Quonset spray enclosure at Tank Farm, with curtained 4$^{th}$ side (dust collector used for filtration, as needed)

Coatings in the cabinet booths are applied using aerosol cans; therefore, these operations are not spray coating operations subject to NWCAA 508, by definition.

PSR has been spray painting piping, structural components, vessels and fabricated assemblies in this spray enclosure located outdoors using high-volume, low-pressure or airless spray guns, for more than 20 years. As such, the spray enclosure is subject to the requirements in NWCAA Section 508. Because the spray enclosure is an existing enclosure located outdoors, it does not have to be equipped with a negative pressure ventilation system, filtration system, nor exhaust stack. Coating operations performed within the Quonset building are required to meet spray application and work practice standards, as well as keep records.

### 2.2.10 NWCAA Section 580.6 – Gasoline Dispensing Facilities

Vapor control requirements in NWCAA Section 580.6(b) apply to all gasoline dispensing facilities with an annual 12-consecutive month throughput equal to or greater than 120,000 gallons. PSR's gasoline fleet vehicle fueling tank does not have annual throughput equal to or greater than 120,000 gallons.

However, in order to be exempt from the rest of NWCAA Section 580.6, the fleet vehicle fueling tank must have:

- a capacity less than 2,000 gallons if installed before January 1, 1990;
- offset fill lines installed before January 1, 1990; or
- a capacity less than 264 gallons.

PSR has one aboveground gasoline storage tank with a capacity of 2,000 gallons and is therefore subject to NWCAA 580.6.

### 2.2.11 Continuous Emission Monitoring Systems

Continuous Emission Monitoring Systems (CEMS) are mandated via a variety of mechanisms, including federal rules (e.g., NSPS, NESHAP/MACT, Acid Rain) and construction permits (e.g., OACs, PSD). Table 2-11 lists the CEMS at PSR and the type of requirement that mandates its use.

**Table 2-11: CEMS at PSR**

| Process Unit | CEMS Location | Compounds Monitored | Type of Requirement |
|---|---|---|---|
| VPS | F4 Stack | $NO_X$, $O_2$ | OAC 929b |
| VPS | F5-F6 Stack | $NO_X$, $O_2$ | OAC 919a |
| FCCU | Main Fuel Gas Drum | $H_2S$ | NSPS J/CO 07 |
| FCCU | Wet Gas Scrubber | $NO_X$, $SO_2$, CO, $O_2$ | OAC 623f, NSPS J/CO 10, MACT UUU |
| HTU 1 | Heater Stack (common stack to 7C-F4 and 7C-F5) | $SO_2$, $O_2$ | NSPS J |
| HTU 2 | HTU #2 Fuel Gas Drum | $H_2S$ | NSPS J/CO 07 |
| HTU 3 | HTU #3 Fuel Gas Drum | $H_2S$ | NSPS J, OAC 787h |
| SRU | Primary Incinerator Stack (SRU3) | $SO_2$, $O_2$ | OAC 828a, NSPS J, MACT UUU |
| SRU | SRU4 Incinerator Stack | $SO_2$, $O_2$ | OAC 828a, NSPS J, MACT UUU |
| Cogens | Cogen 1, 2, 3 Stacks | $NO_X$, $NH_3$, CO, $SO_2$, $O_2$ | OAC 475i, OAC 476h, NSPS GG, NSPS J, NSPS Db |
| Flare | East Flare | $H_2S$, $SO_2$ | NSPS Ja |

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 As list 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 also 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. Data accuracy assessments shall be performed at least once every calendar quarter. This entails 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 on a monthly basis.

In addition, CEMS performance is required to be submitted to NWCAA on a monthly basis. 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.

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, Shell updates this information in the monthly reports.

### 2.2.12 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 required PSR to conduct and record monthly qualitative observations of the refinery combustion unit stacks. If visible emissions are observed, PSR 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.

For visible emissions associated with spray coating operations, NWCAA required PSR to conduct and record qualitative observations of the effectiveness of the capture and control of paint overspray within the Quonset building during each use of the Quonset building for spray coating. If it is determined that capture and control of paint overspray are ineffective (i.e., visible paint overspray is escaping the Quonset building), the dust collector will be used for filtration. Observations will be recorded each time the Quonset building is used for spray coating, including annotation if dust collector use was required.

Visible observation monitoring under AOP Section 6.1 is also used to determine ongoing compliance with various particulate emission standards (e.g., 0.05 grain/dscf under NWCAA 455). Although particulate emission rates are not directly linked to opacity, a zero percent opacity action level is likely to ensure that emissions are less than the applicable grain loading standard. This surrogate monitoring approach ensures proper operation of equipment, thereby reducing the potential for particulate emissions from the emissions unit.

### 2.2.13 Compliance Assurance Monitoring

40 CFR Part 64 Compliance Assurance Monitoring (CAM) is intended to provide a reasonable assurance of compliance with applicable requirements under the Clean Air Act for large emission units that rely on pollution control device equipment to achieve compliance. The CAM rule (40 CFR Part 64) requires owners and operators to conduct monitoring to determine that control measures, once installed or otherwise employed, are properly operated and maintained so that they continue to achieve a level of control that complies with applicable requirements.

The CAM approach establishes monitoring for the purpose of:

- Documenting continued operation of the control measures within ranges of specified indicators of performance that are designed to provide a reasonable assurance of compliance with applicable requirements,
- Indicating any excursions from the performance indicator ranges, and
- Responding to the data so that the cause or causes of the excursions are corrected.

The first step in the CAM process is to determination the applicability of CAM to each pollutant-specific emission unit (PSEU). The determination is made on a pollutant-by-pollutant basis for each emission unit. To be subject to CAM, the PSEU must be:

1. Located at a major source required to obtain a Part 70 permit,
2. Subject to an emission limit or standard for the applicable pollutant,
3. Use a control device to achieve compliance,
4. Have potential pre-control emissions of the applicable pollutant that are at least 100% of major source threshold, and
5. Not otherwise exempt

PSR is a major source required to obtain a Part 70 permit, so all emission units at the refinery are potentially subject to CAM. Only one PSEU triggers the requirement to submit a CAM plan – the fluidized catalytic cracking unit (FCCU) controlled by wet gas scrubber (WGS). Table 2-12 identifies the CAM triggers and provides a summary of the CAM applicability review. Table 2-13 lists other emission units at the facility and explains why CAM does not apply to these emission units.

Sources required to submit CAM plans must include:

- The approved monitoring approach, including the indicators (or the means to measure the indicators) to be monitored, and the 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.

**Table 2-12: CAM Applicable**

| Pollutant-Specific Emission Unit | Control Device | Pollutant | Emission Limit | Pre-controlled Emissions |
|---|---|---|---|---|
| FCCU – CO Boilers & Regenerator | Wet Gas Scrubber (WGS) | • PM<br>• $PM_{10}$<br>• Visible Emissions | • 0.2 gr/dscf<br>• 0.02 gr/dscf<br>• 40%, 3 min aggregate/hr;<br>20%, 6 min/hr | > 202 tpy (Permitted PTE) |

The strategy proposed by PSR in the CAM plan (included in Appendix A) is to demonstrate compliance with the state and NWCAA regulations grain per dry standard cubic foot (gr/dscf, aka grain loading) particulate matter limits and state and OAC 623f percent (%) opacity visible emission standards by continuously monitoring WGS performance, as specified in the Alternative Monitoring Plan (AMP) approved by EPA (most recently, 9/9/19). The AMP was approved in lieu of installation and operation of a continuous opacity monitor (COM) for compliance demonstration in 40 CFR 63 Subpart UUU because gases exiting the WGS are saturated with water vapor making continuous direct measurement of particulate matter and visible emissions impractical.

These continuously monitored operating parameters are correlated with particulate grain loading data and visible emission measurements taken during annual PM/$PM_{10}$ source tests, confirming that continuously meeting the minimum liquid-to-gas ratio (L/G) established during the initial performance test assures on-going compliance with particulate and visible emission limitations.

The FCCU has a controlled potential-to-emit above 100 tons per year and is considered a "large PSEU", requiring monitoring parameters be recorded at least once every 15 minutes. Scrubber liquid flow rate (calculated from a formula based on the manufacturer's pump curve) and WGS inlet gas flow rate (calculated using process meters on the FCCU and CO Boilers and verified during annual source testing) are continuously monitored and the 3-hour rolling average L/G calculated to satisfy this requirement. A computer alarm notifies operations personnel of low L/G. Further discussion of the details of the CAM plan for the FCCU controlled by WGS can be found in SofB Section 3.3.

Table 2-13 provides a summary of the CAM applicability review for the remaining PSEUs on site (based upon a more detailed review that can be found in the agency's AOP renewal review file). The table identifies the PSEU, pollutant, whether there is a control device other than inherent process equipment provided for safety or material recovery or passive methods that prevent pollutants from forming (e.g., low NOx burners, lids or seals, etc) used to destroy or remove pollutants prior to discharge to the atmosphere to achieve compliance, and the basis for the non-applicability determination. A determination of non-applicability at a unit otherwise exempt due to being subject to a standard under 40 CFR Part 60 (NSPS), 40 CFR Part 61 (NESHAP), or 40 CFR Part 63 (MACT), is based on the date the final rule is promulgated instead of the proposal date, as all of the federal standards applicable at PSR that were proposed before November 15, 1990 were also finalized before November 15, 1990.

**Table 2-13: Emission Units and Pollutants Not Subject to CAM**

| Refinery Process Area | PSEU | Pollutant - Control Device | Reason(s) for Non-Applicability |
|---|---|---|---|
| | | NOx – Low NOx burners | Passive control device |

| Refinery Process Area | PSEU | Pollutant - Control Device | Reason(s) for Non-Applicability |
|---|---|---|---|
| Vacuum Pipe Still Unit | • 1A-F4 Gas Oil Tower Heater<br>• 1A-F5/F6 Atm Charge Heater<br>• 1A-F8 Vacuum Charge Heater | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| Delayed Coking Unit | • 15F-100 Charge Heater | NOx – Low NOx burners | Passive control device |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| | • LR-7 Coke Loading | PM & Visible Emissions - Uncontrolled | No control device |
| Fluid Catalytic Cracking Unit | • FCCU Regenerator / CO Boilers | $NO_X$ – Wet Gas Scrubber | Otherwise exempt - Equipped with continuous compliance determination method - CEMS |
| | | CO – CO Boilers | Otherwise exempt - Equipped with continuous compliance determination method - CEMS |
| | | $SO_2$ – Wet Gas Scrubber | Otherwise exempt - Equipped with continuous compliance determination method - CEMS |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | Metal HAP/PM & Visible Emissions – Wet Gas Scrubber | Otherwise exempt – Subject to MACT UUU (**4/11/02**) |
| | • Fresh Catalyst Hopper | PM & Visible Emissions – Truck-mounted Baghouse | Pre-controlled emissions estimated at 1.5 tons/year, less than 100% of major source threshold |
| Catalytic Reforming Units | • 10H-101 Charge Heater<br>• 10H-102&103 Interheaters | NOx – Low NOx burners | Passive control device |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Opacity - Uncontrolled | No control device |
| | • 10H-104 Stablizer Reboiler | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| | • CRU2 Regen Drum Vent | HCl – Internal Caustic Scrubber, Routed to Flare | Otherwise exempt – subject to MACT UUU (**4/11/02**) |

| Refinery Process Area | PSEU | Pollutant - Control Device | Reason(s) for Non-Applicability |
|---|---|---|---|
| Hydrotreater Units | • 7C-F4 Charge Heater @ HTU1<br>• 7C-F5 Fractionator Reboiler @ HTU1<br>• 11H-101 Charge Heater @ HTU2<br>• 11H-102 $H_2S$ Stripper Reboiler @ HTU2<br>• 11H-103 Fractionator Reboiler @ HTU2 | NOx – Low NOx burners | Passive control device |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| | • HTU3 – 60-F201 CDHDS Heater | NOx – Ultra Low NOx burners | Passive control device |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| Sulfur Recovery Units | • Sulfur Recovery Unit #3<br>• Sulfur Recovery Unit #4 | $SO_2$ – Incinerator | Otherwise exempt – Subject to MACT UUU (**4/11/02**); Subject to NSPS J (3/8/74) → Complies by relying upon NSPS Ja (**6/24/08**); Equipped with continuous compliance determination method - CEMS |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| Utilities | • Erie City Boiler | PM & Visible Emissions - Uncontrolled | No control device |
| | • Cogen 1 & 2<br>• Cogen 3 | NOx – Steam Injection & SCR | Otherwise exempt – equipped with a continuous determination method - CEMS |
| | | $NH_3$ - Uncontrolled | No control device |
| | | CO - Uncontrolled | No control device |
| | | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |

| Refinery Process Area | PSEU | Pollutant - Control Device | Reason(s) for Non-Applicability |
|---|---|---|---|
| | | PM & Visible Emissions - Uncontrolled | No control device |
| RP&S | • LR-1 Gasoline / Diesel Truck Unloading Terminal | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| | | VOC/HAP – Vapor Combustor | Otherwise exempt – Subject to NSPS XX (8/18/83) & MACT CC (**8/18/95**) |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| | • Ethanol Unloading & Storage | VOC – Floating Roof | Passive control device |
| Tank Farm | • Storage Tanks | VOC/HAP – Floating Roof with Seals | Passive control device, no emission limit |
| Flare System | • 19N-F1<br>• 19N-F2<br>• 19N-F3 | $SO_2$ – Uncontrolled | No control device.<br>Otherwise exempt – Subject to NSPS Ja (**6/24/08**) |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| | • Flare Gas Recovery | $SO_2$ – Amine Treatment System | See last line of table, "Fuel gas $S_2$ content" controlled by Amine System |
| Generators | • 30LEG2 Control Room #2<br>• 33PGE3 BOHO Emergency Firewater Pump<br>• 33PTE14 & 15 BOHO Firewater Pumps<br>• 30LEG5Wharf Standby Generator | $SO_2$ - Uncontrolled | No control device |
| | | PM & Visible Emissions - Uncontrolled | No control device |
| | • 30LEG6 Main Control Room Generator<br>• 30LEG7 Radio Tower Emergency Generator | NMHC + NOx - Uncontrolled | No control device |
| | | CO - Uncontrolled | |
| | | $SO_2$ - Uncontrolled | |
| | | PM & Visible Emissions - Uncontrolled | |

| Refinery Process Area | PSEU | Pollutant - Control Device | Reason(s) for Non-Applicability |
|---|---|---|---|
| | • 9QG68 EP Outfall Pump | NOx – Exhaust Gas Recirculation | Otherwise exempt – Subject to NSPS IIII (**7/11/06**) / MACT ZZZZ (**6/15/04**) |
| | | NMHC - Uncontrolled<br>CO - Uncontrolled<br>$SO_2$ - Uncontrolled | No control device |
| | | PM & Visible Emissions – Particulate Filter; Coalescing Filter for Crankcase | Pre-controlled emissions estimated at 0.75 tons/year, less than 100% of major source threshold |
| Wastewater System | • Effluent Plant & Sewer System | VOC/HAP – Closed Vent System & Carbon Canisters | No emission limit |
| | • Effluent Plant Tanks | VOC/HAP – Floating Roof | Passive control device, no emission limit |
| Misc. Systems | • Fugitive Emissions from Leaking Equipment Components | VOC/HAP – Routed to Flare | No emission limit<br>Otherwise exempt – Subject to NSPS VV (10/18/83), GGG (5/30/84), GGGa (**11/16/07**)/MACT CC (**8/18/95**) which references NSPS A (12/23/71)/MACT A (**3/16/94**) |
| | | VOC/HAP – Uncontrolled | |
| | • Heat Exchangers | HAP – Uncontrolled | No control device |
| | • Misc Process Vents | HAP – Routed to Flare | No emission limit<br>Otherwise exempt – Subject to MACT CC (**8/18/95**) |
| | • Catalyst Reforming Vents | HAP (organic/inorganic) - Uncontrolled | No control device |
| | • Process Drains | VOC/HAP – Routed to Flare or Carbon Canister | No emission limit<br>Otherwise exempt – Subject to NSPS QQQ (11/23/88)/NESHAP FF (3/7/90)/MACT CC (**8/18/95**) |
| | | VOC/HAP – Covered | Passive control device |
| | | VOC/HAP – Uncontrolled | No control device |
| | • Spray Coating | PM & Visible Emissions – Uncontrolled | No control device |
| | • Gasoline Dispensing (2000 gallon AGT) | VOC/HAP – pressure vacuum vent cap, maintained in vapor-tight condition | No control device |
| Fuel Gas $S_2$ Content | • Fuel Gas Combustion in various units | $H_2S$ – Amine Treatment System | Otherwise exempt – Equipped with continuous compliance determination method - CEMS |

Note that in this CAM applicability analysis, pre-controlled emissions are not calculated when:

- a control device is not used to achieve compliance,
- there are no emission limits or standards that apply, or
- the PSEU is otherwise exempt.

A PSEU is otherwise exempt when subject to:

- Post-11/15/90 proposed NSPS or NESHAP, as those standards were designed with monitoring that provides a reasonable assurance of compliance
- Stratospheric ozone protection requirements
- Acid rain program requirements
- Emission limitations, standards, or other requirements that apply solely under an approved emission trading program
- Emissions cap that meets the requirements of §70.4(b)(12)
- Emission limitations or standards for which a Part 70 permit specifies a continuous compliance determination method that does not use an assumed control factor, such as a CEMS used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard and provides data in units of the standard.

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

Fuel gas combustion devices are subject to fuel gas sulfur content requirements to limit $SO_2$ emissions. The amine system at the refinery acts to remove sulfur from the fuel gas which is then burned in the fuel gas combustion devices, therefore CAM applicability is addressed as an individual line item for fuel gas sulfur content in the table.

Flares can be considered emission sources themselves with emission limits but also control devices for other refinery sources (e.g., miscellaneous process vents). The flare as an emission source does not have any active control equipment to meet the emission standards (e.g., opacity, $SO_2$); therefore, CAM does not apply directly. However, when the flare serves as the control device (e.g., MPVs, equipment leaks), CAM is addressed for the controlled unit (see Table 2-7 above).

Several emission units are required to monitor operations with a CEMS (e.g., fuel sulfur content under NSPS J, $NO_X$ on the Cogens under OAC 475i and 476h and NSPS GG, $SO_2$ on FCCU). These CEMS are also subject to NWCAA 367 and NWCAA Appendix A which requires quality assurance for the CEMS. As such, the CEMS is considered a continuous compliance determination method, which exempts it from CAM requirements.

Certain emission units for specific pollutants are subject to multiple overlapping NSPS, NESHAP, and MACT which rely on each other for the compliance demonstration to streamline the requirements (e.g., NSPS J and MACT UUU at the SRUs and FCCU; NESHAP FF and MACT CC at the Effluent Plant; NSPS QQQ, NESHAP FF, and MACT CC for process drains; NSPS XX and MACT CC at the Truck Rack Vapor Combustor; MACT A and CC for the flare). It is assumed in this analysis that when a newer post-November 5, 1990 rule utilizes an older rule for the compliance demonstration, the older rule's compliance demonstration is adequate for CAM and qualifies for the exemption.

### 2.2.14 Risk Management Plan (RMP)

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.

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

### 2.2.15 Chapter 173-441 WAC – Reporting of Emissions of Greenhouse Gases

Greenhouse gases are chemicals that contribute to climate change by trapping heat in the atmosphere. The greenhouse gases recognized by EPA and Ecology are: carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride ($SF_6$). "Hydrofluorocarbons" or "HFCs" means a class of greenhouse gases primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

PSR is required to meet Chapter 173-441 WAC, "Reporting of Emissions of Greenhouse Gases", which adopts a mandatory greenhouse gas reporting rule for:

- Suppliers that supply applicable fuels sold in Washington state of which the complete combustion or oxidation would result in at least 10,000 metric tons of carbon dioxide annually; or
- Any listed facility that emits at least 10,000 metric tons of carbon dioxide equivalents ($CO_2e$) of greenhouse gases annually in the state.

Chapter 173-441 WAC was adopted by Ecology on December 1, 2010 and became effective on January 1, 2011. This regulation applies to PSR due to the fact that it emits at least 10,000 metric tons of $CO_2e$ of greenhouse gases per year (see Table 1-3). The rule requires annual GHG inventories due to Ecology by no later than March 31 of the following year beginning for calendar year 2012. This regulation is implemented in its entirety by Ecology. Because the statutory authority for Chapter 173-441 WAC was the state Clean Air Act (Chapter 70.94 RCW), it is considered an applicable requirement under the air operating permit program (WAC 173-401-200(4)); as such, it is included in the AOP.

## 2.3 Inapplicable Requirements

### 2.3.1 Equilon Consent Decree and Heater and Boiler Consent Decree

On August 20, 2001, Equilon Enterprises LLC dba Shell Oil Products US (i.e., Shell PSR) entered into consent decrees applicable to PSR in the following cases:

United States, et al. v. Equilon Enterprises LLC, et al.
United States District Court for the Southern District of Texas
Civil Action No. H-01-0978
(Referred to in the SofB as the Heater and Boiler Consent Decree)
***Terminated on August 1, 2013***

United States, et al. v. Equilon Enterprises LLC
United States District Court for the Southern District of Texas
Civil Action No. H-01-0978
(Referred to in the SofB as the Equilon Consent Decree)
***Terminated on May 5, 2016***

These Consent Decrees were issued to Equilon Enterprises LLC based on alleged violations of the federal Prevention of Significant Deterioration (PSD) program, major New Source Review (NSR), New Source Performance Standards (NSPS) 40 CFR 60 Subpart J, National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 61 Subpart FF, and Leak Detection and Repair (LDAR) 40 CFR 60 and 63 at various Shell-owned facilities across the country, including PSR. The Consent Decrees included a compliance schedule with specific compliance obligations and air pollution control measures (e.g., application of NSPS Subpart J standards to all refinery fuel gas combustion units and flares, installation of a wet gas scrubber on the fluid catalytic cracking unit, and retrofitting several combustion devices with ultra-low NOx burners) applicable to PSR.

Each Consent Decree includes the ability for the company to terminate the Consent Decree once the requirements are satisfied, including payment of all penalties, installation of required control equipment, the receipt of all mandated permits, and operation for at least one year in compliance with Consent Decree emission limits. To ensure that certain Consent Decree requirements are federally enforceable after the Consent Decree "sunsets", pursuant to the Consent Decree, the NWCAA issued orders of approval to construct (OAC) or compliance orders (CO) for ongoing compliance with these requirements. These NWCAA-issued orders have been incorporated into the AOP as specific requirements.

As the Heater and Boiler Consent Decree was terminated on August 1, 2013 and the Equilon Consent Decree was terminated on May 5, 2016, these Consent Decrees are no longer applicable requirements.

### 2.3.2 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. Nonene is a listed SOCMI chemical under Subpart NNN and the Nonene Unit utilizes distillation to separate out the C9 material; as such, the Nonene Unit is potentially subject to Subpart NNN.

However, the Nonene Unit does not discharge its vent streams to the atmosphere directly or indirectly – the nonene product stream is routed to final product tankage and the remaining hydrocarbon stream (still referred to as poly gasoline) is routed to tankage for gasoline blending. As such, 40 CFR 60 Subpart NNN does not apply.

### 2.3.3 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.

### 2.3.4 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 the feed into the ISOM Unit (i.e., into the BenSat Unit) at 5.5 wt% benzene. The next highest concentrations are in the CRU2 light and heavy platformate streams and the HTU3 light and heavy naphtha streams (HTU3 feed is from the FCCU). As such, no streams at the refinery are subject to 40 CFR 61 Subpart J.

### 2.3.5 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 has the potential to trigger Subpart BB during an event where the Isomerization (ISOM) Unit is shut down for an extended period and the refinery is in a position to ship out the benzene-rich Isomerization unit feedstock in lieu of processing. Note that the ISOM Unit feed stream is approximately only 5.5 wt% benzene. As such, should this occur, PSR is potentially subject to the recordkeeping and reporting requirements under Subpart BB. However, the refinery does not anticipate a scenario

where an extended Isomerization unit shutdown is likely. Therefore, these requirements are not listed in the AOP. However, in the unlikely event that PSR does ship the ISOM feed stream offsite, it will be subject to Subpart BB requirements.

### 2.3.6 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 Nonene Unit is a SOCMI unit for the purposes of NSPS – nonene is a listed chemical. However, nonene is not a listed SOCMI chemical under MACT. As such, the nonene unit is not subject to the SOCMI requirements under MACT. Further, in accordance with §63.100(j)(2), Subparts F, G and H are not applicable to petroleum refinery process units.

### 2.3.7 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 the refinery cooling towers nor the cooling towers associated with the Cogen units used 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.

### 2.3.8 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 five percent by weight or greater of 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. 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 Nonene Unit and load rack are not subject to another MACT standard (the nonene storage tanks are subject to the Group 2 requirements under 40 CFR 63 Subpart CC). However, the HAP content of the handled material is not greater than 5% by weight. As such, it is not subject to Subpart EEEE.

The propane/butane loading rack is not subject to another MACT standard. However, propane/butane is not a liquid at ambient pressures. As such, it is not an organic liquid and is not subject to Subpart EEEE.

Tank 20 is a 1,680,000 gallon external floating roof tank that stores sour water and is not subject to another MACT standard. Sour water does not have a HAP content greater than 5% by weight; as such, it is not subject to Subpart EEEE.

Tank 64 is a 7,600 gallon fixed roof tank that is not subject to any other MACT provisions. This tank used to store Nalco 5300 stabilizer oil additive, which is considered an organic liquid under Subpart EEEE, therefore it was considered an affected source under Subpart EEEE. The tank has been out of service for ~ 10 years and the refinery has no plans to reactivate the tank, therefore Subpart EEEE does not apply. Should the tank ever be reactivated, PSR will need to evaluate applicability based on whatever product would be stored in the tank.

Note that the blending chemicals stored in other facility tanks do not qualify as organic liquids and, as such, are not subject to Subpart EEEE.

In the unlikely event that the ISOM Unit is shut down for an extended period, PSR may choose to ship out the benzene-rich unit feedstock in lieu of processing. The feed stream is approximately 5.5 wt% benzene. As such, the stream qualifies as an organic liquid under Subpart EEEE and the loadout potentially triggers Subpart EEEE requirements. However, because this scenario would most likely be part of maintenance or an upset, any equipment required for the loadout would be non-permanent and, under 40 CFR 63.2338(c)(2), would be exempt from Subpart EEEE requirements. Should this event occur and some of these assumptions not be the case, Subpart EEEE requirements may apply. Because this event is so unlikely, Subpart EEEE requirements are not listed in the AOP for the ISOM Unit.

PSR receives denatured ethanol primarily via train car and blends it into the gasoline as it is loaded out by truck. At first glance, the ethanol could be considered an organic liquid under Subpart EEEE. However, an organic liquid under Subpart EEEE must include 5 wt% of the listed HAP. Ethanol is not a HAP but it is denatured using 5 wt% gasoline or natural gasoline. To reach the 5 wt% HAP threshold in Subpart EEEE, gasoline and natural gasoline will need to be pure HAP, which is not the case. In addition, Subpart EEEE exempts gasoline from being a subject organic liquid. As such, Subpart EEEE does not apply to the ethanol unloading and storage.

### 2.3.9 40 CFR 63 Subpart FFFF – Miscellaneous Organic Chemical Manufacturing (MON)

40 CFR 63 Subpart FFFF applies to the emissions of HAPs from miscellaneous organic chemical manufacturing process units (MCPU) located at, or part of, a major sources of HAP emissions. An MCPU includes equipment necessary to operate a miscellaneous organic chemical manufacturing process that is satisfies ALL the following conditions:

1. The MCPU produces material or family of material that is an organic chemical classified using:

- the 1987 version of SIC code (282, 283, 284, 285, 286, 287, 289 or 386, with a few exceptions; the 1997 version of NAICS code 325, with a few exceptions;
- Quaternary ammonium compounds and ammonium sulfate produced with caprolactam;
- Hydrazine; or
- Organic solvents classified in any of the SIC or NAICS codes listed above that are recovered using nondedicated solvent recovery operations.

2. The MCPU processes, uses, or generates any organic HAPs, or hydrogen halide and halogen HAP.

3. The MCPU is not an affected source or part of an affected source under another subpart of this part 63, except for process vents from batch operations within a chemical manufacturing process unit (CMPU), as identified in the SOCMI MACT, §63.100(j)(4).

Potential miscellaneous organic chemical manufacturing processes at PSR include production of propylene from refined petroleum or liquid hydrocarbons. However, propylene is a by-product of the refining process, and is utilized within the refinery as feedstock for the alkylation units (Alky1 & Alky2) and catalytic polymerization unit (CPU). In addition, the CPU and both Alky units are part of an affected source under another part 63 subpart, therefore, Subpart FFFF would not be applicable.

### 2.3.10 Title IV Acid Rain Program

Title IV of the Clean Air Act authorizes the EPA to establish the Acid Rain Program. The purpose of the Acid Rain Program is to significantly reduce emissions of sulfur dioxide and nitrogen oxides from utility electric generating plants in order to reduce the resultant adverse health and ecological impacts of acidic deposition (or acid rain). The EPA promulgated these rules in 40 CFR 72, 73, 74, 75, 77 and 78 on January 11, 1993 and March 23, 1993. Ecology also incorporated the Acid Rain program into Chapter 173-406 WAC effective on December 24, 1994.

PSR provided a determination letter issued by EPA dated July 29, 1994 stating that because PSR is a qualifying facility that had, as of, November 15, 1990, one or more qualifying power purchase commitments to sell at least 15% of its total net output capacity, the Cogen Units are not "affected units" under the Acid Rain Program pursuant to 40 CFR 72.6(b)(5) and, therefore, are not subject. However, the regulations limit the exempted facility to 130% of the total planned net output capacity. Thus, if more than 182 MWe of net output capacity is ever constructed at the facility, one or more units serving the capacity in excess of 182 MWe will become affected by the Acid Rain Program requirements.

### 2.3.11 40 CFR 98 – Federal Mandatory Greenhouse Gas Emission Inventory Regulation

This regulation applies to PSR 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 to PSR, 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).

### 2.3.12 Chapter 173-407 WAC – Carbon Dioxide Mitigation Program, Greenhouse Gases Emissions Performance Standard and Sequestration Plans and Programs for Thermal Electric Generating Facilities (Part I WAC 173-407-010 through -070, and Part II, WAC 173-407-100 through -320)

Chapter 173-407 WAC, "Carbon Dioxide Mitigation Program, Greenhouse Gases Emissions Performance Standard And Sequestration Plans And Programs For Thermal Electric Generating Facilities", consists of two parts: Part I, WAC 173-407-010 through -070, and Part II, WAC 173-407-100 through -320. According to WAC 173-407-005, Part II, "Greenhouse Gases Emissions Performance Standard And Sequestration Plans And Programs For Baseload Electric Generation Facilities Implementing Chapter 80.80 RCW", is the emissions performance standard that must be met first. Then the requirements of Part I, "Carbon Dioxide Mitigation For Fossil-Fueled Thermal Electric Generating Facilities, Implementing Chapter 80.80 RCW", are applied.

The Part II greenhouse gas emissions performance standard is applicable to all existing baseload electric cogeneration facilities and units when, among other situations, the existing facility or unit is subject to a change in ownership (WAC 173-407-120(4)(c)). The cogeneration facility is a baseload facility that began operation in the early 1990s as March Point Cogeneration Company (MPCC). PSR took ownership of MPCC on February 1, 2010. As such, the Cogens are subject to the emission standard for Greenhouse Gases of 1,100 lb/MW-hr. With the applicability of the emission standard, PSR must perform the mandated monitoring, testing, and reporting. This regulation is implemented in its entirety by Ecology. Additionally, this regulation is excluded from appearing in the AOP because it does not contain applicable requirements under the Title V program (WAC 173-401-200(4)).

Part I requirements of the regulation only apply during the permitting of new fossil-fueled thermal electric generating facilities and expansions of existing fossil-fueled thermal electric generating facilities (i.e., an increase in station-generating capability of greater than 25 MWe or an increase in $CO_2$ emissions output by 15% or more). Because the PSR cogeneration facility was constructed prior to July 1, 2004 and the generation capacity has not been expanded since, Part I of the Chapter 173-407 WAC does not apply.

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

PSR 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 24, 2014 when the 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 2,003,779 metric tons. The report included a letter from Solomon Associates that certified that PSR has a calculated EII that meets the Energy Efficiency Standard in WAC 173-485-040(1) and that using calendar year 2012 operational data, PSR'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), PSR has no further reporting or compliance obligations under Chapter 173-485 WAC and it is therefore not listed in the AOP.

# 3. PROCESS DESCRIPTIONS, CONSTRUCTION HISTORY AND REGULATORY DISCUSSION

The following section provides a description of each refinery process area along with a brief construction history. For further detail regarding the construction permit history or issued OACs, see the previous version of the AOP SofB or specific permitting documentation.

The refinery areas are presented in the same order found in the AOP for ease in cross-referencing. The construction history provides valuable insight into 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 requirement there is no need to discuss the term further in the SofB. However, where gap filling has occurred, a regulatory interpretation has been made, or where the level of regulatory complexity warrants clarification, they are discussed herein.

## 3.1 Vacuum Pipe Still (VPS)

Sometimes referred to as the Crude Unit, the Vacuum Pipe Still (VPS) is considered the first stage of crude processing at the refinery. Here, crude oils are "washed" in the Desalter to remove salts and other naturally occurring contaminants. After washing, the crude is heated to about 650°F in the 1A-F5 & 1A-F6 charge heaters and then routed to the Atmospheric Distillation Tower where it physically separates into fractions with specific boiling point ranges. Further separation is achieved by distillation under vacuum at the Vacuum Pipe Still or by steam stripping. The light fractions, such as propane, naphtha, kerosene, and diesel, generated from atmospheric distillation can be further processed or used as finish product blending stocks often referred to as "straight run" products. Heavier fractions are routed to the Gas Oil Distillation Tower where gas oils are separated before routing to the FCCU as feedstock. The heaviest fractions are produced from the bottom of the VPS and are called vacuum residuum. The vacuum residuum is sent to the DCU as a feedstock or can be blended into heavy finished products such as bunker or marine fuel oils.

The charge rate capacity of the VPS is dependent on the characteristics of the crude oils that are processed. This is a result of different heat loads needed for processing and the fact that differing crude oils will produce different product mixes during processing.

Major equipment at the VPS include the desalters, flash drum, heaters, atmospheric tower, gas oil tower, side strippers, vacuum tower, accumulator drums, and coalescers. Operating temperatures range from ambient to 780 °F. Operating pressures range from 6 mm Hg to 450 psi. The unit has a number of components in heavy liquid, light liquid, and gaseous service that can emit fugitive VOC and HAPs. Other activities that may result in emissions to the air are conducted periodically to properly operate and maintain the equipment.

### Construction History and Regulatory Discussion

The original crude unit was built with the refinery in 1958. In 1975, two new charge heaters and a gas oil heater were installed as part of the Octane Improvement project.

**Gas Oil Heater (1A-F4) and Atmospheric Charge Heaters (1A-F5 & 1A-F6):** During early 2000, PSR voluntarily installed low $NO_X$ burners on VPS heaters 1A-F5 and 1A-F6. OAC 919 on September 12, 2005 was issued to incorporate the emissions limits and emissions reductions from this installation of low $NO_X$ burners in the VPS heaters into federally enforceable permit requirements as required by the Consent Decree. However, the unit was not "modified" for the purposes of new source review or NSPS. As such, NSPS requirements were not triggered as a result of this project. OAC 919 has since been revised to OAC 919a (issued April 12, 2013) for non-construction-related regulatory applicability and verbiage changes.

Similarly, OAC 929 was issued on September 12, 2005 permitting the installation of low $NO_X$ burners in heater 1A-F4 as required by the Heater and Boiler Consent Decree with an emission limit of 0.035 lb/MMBtu on a 12-month average. This project did not trigger NSPS requirements. When testing demonstrated that the burners were not able to meet the guaranteed limit, OAC 929a was issued to include a less stringent limit (0.06 lb/MMBtu on a 12-month rolling average). OAC 929a has since been revised to OAC 929b (issued April 12, 2013) for non-construction-related regulatory applicability and verbiage changes. All (3) heaters trigger 40 CFR 63 Subpart DDDDD as existing units designed to burn gas 1.

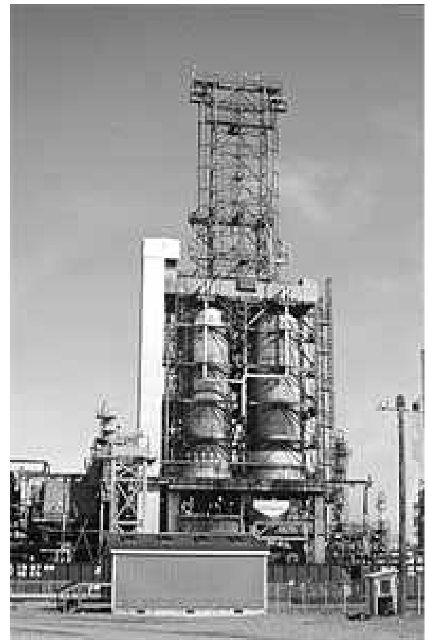
**Vacuum Charge Heater (1A-F8):** In late 1999, the vacuum tower (1A-C103) and associated vacuum tower heater (1A-F8) were replaced. This project triggered NSPS Subpart J as a fuel gas combustion device and NSPS Subpart GGG for equipment leaks. Construction related to this unit upgrade was approved by the NWCAA on June 17, 1999 under OAC 684. OAC 684 has since been revised to OAC 684b (issued May 3, 2010) for non-construction-related regulatory applicability and compliance demonstration changes. Vacuum tower heater (1A-F8) triggers 40 CFR 63 Subpart DDDDD as an existing unit designed to burn gas 1.

**VPS Tower (1A-C1) Atmospheric PRDs:** With the RTR initiative, new operating and pressure relief requirements and management of releases were added to Refinery MACT 1 for pressure relief devices (PRDs) that release to atmosphere. To meet these requirements, PSR has instituted three redundant measures to prevent the release to atmosphere and a mechanism to notify operations if there is a release on the 11 atmospheric PRDs on Tower 1A-C1 at the VPS unit.

**VPS Process Improvement (PI) Project:** PSR proposed upgrades to the VPS unit to increase operational reliability and flexibility mid-2016. OAC 1253 was approved October 21, 2016. Equipment for the project started up in late 2017, including: upgraded existing desalters (2), existing desalter wash-water system, existing atmospheric column overhead system, existing product rundowns from atmospheric column; replaced atmospheric column internal tray, flash drum and pump; and installed new 2$^{nd}$ stage desalters and booster pumps. The OAC requires that an enhanced LDAR program be implemented at the VPS unit consistent with NSPS 40 CFR 60 Subpart VVa standards (by reference through NSPS Subpart GGGa) as BACT. The reconstructed individual drain system is subject to MACT Subpart CC which references requirements in 40 CFR 61 Subpart FF.

**Excluded Conditions:** OAC 1253 Condition 2 requires notification to NWCAA upon startup of the equipment installed per the VPS PI Project. This one-time requirement was satisfied on December 4, 2017 when NWCAA received notice in writing of startup of the equipment associated with this project. As such, OAC 1253 Condition 2 is a one-time requirement that has already been met and therefore is not included in the AOP.

## 3.2 Delayed Coking Unit (DCU)



The Delayed Coking Unit (DCU) converts vacuum residuum from the crude unit into fractions by thermal cracking and coking followed by steam stripping and fractionation. The heavy feed is first heated and then charged to large drums that provide the long residence time needed for thermal cracking and coking to proceed to completion. Cracked products from the coke drums are routed to the DCU fractionator while coked material remains behind as petroleum coke. The lighter cracked fractions are routed to the FCCU and Catalytic Polymerization Unit (CPU). Light to medium fractions such as the Coker Light Gas Oil (CLGO) and Delayed Coker Naphtha are sent to the HTU2 for further processing. Coker Heavy Gas Oil is sent to the FCCU as feedstock. The residual heavy material deposits as solid petroleum coke on the inside of the coke drum. For continuous operation, two drums are used: while one is online, high-pressure water is used to cut the deposited coke out of the other. Prior to cutting, the drum is cooled down using steam and water. Coke-cutting water is recycled using a pair of large settling tanks. Slop oil recovered from the drum is routed to slop oil recovery tanks located at the unit. Recovered oil is sent to the FCCU for processing. Various plant sludges can be charged to the DCU coke drums during the blowdown cycle. After the petroleum coke is removed from the drums it is stockpiled just east of the DCU. Most of the finished coke is loaded into covered trucks and hauled to the Port of Anacortes for loading onto marine vessels.

Major components at the DCU include the fractionator, heater, side strippers, accumulator drums, overhead compressor, deethanizer and debutanizer towers, and slop oil and sour water tanks. Operating temperatures range from ambient to 925°F. Operating pressures range from 0.5 to 450 psi. The high-pressure water cutter for removing coke from the coke drums operates at 3000 psi. Equipment and emission units are identified in the process flow diagram below. The unit also has a number of components in heavy liquid service that can emit fugitive VOC and HAP emissions. Other activities that may result in emissions to the air are conducted periodically to properly operate and maintain the equipment.

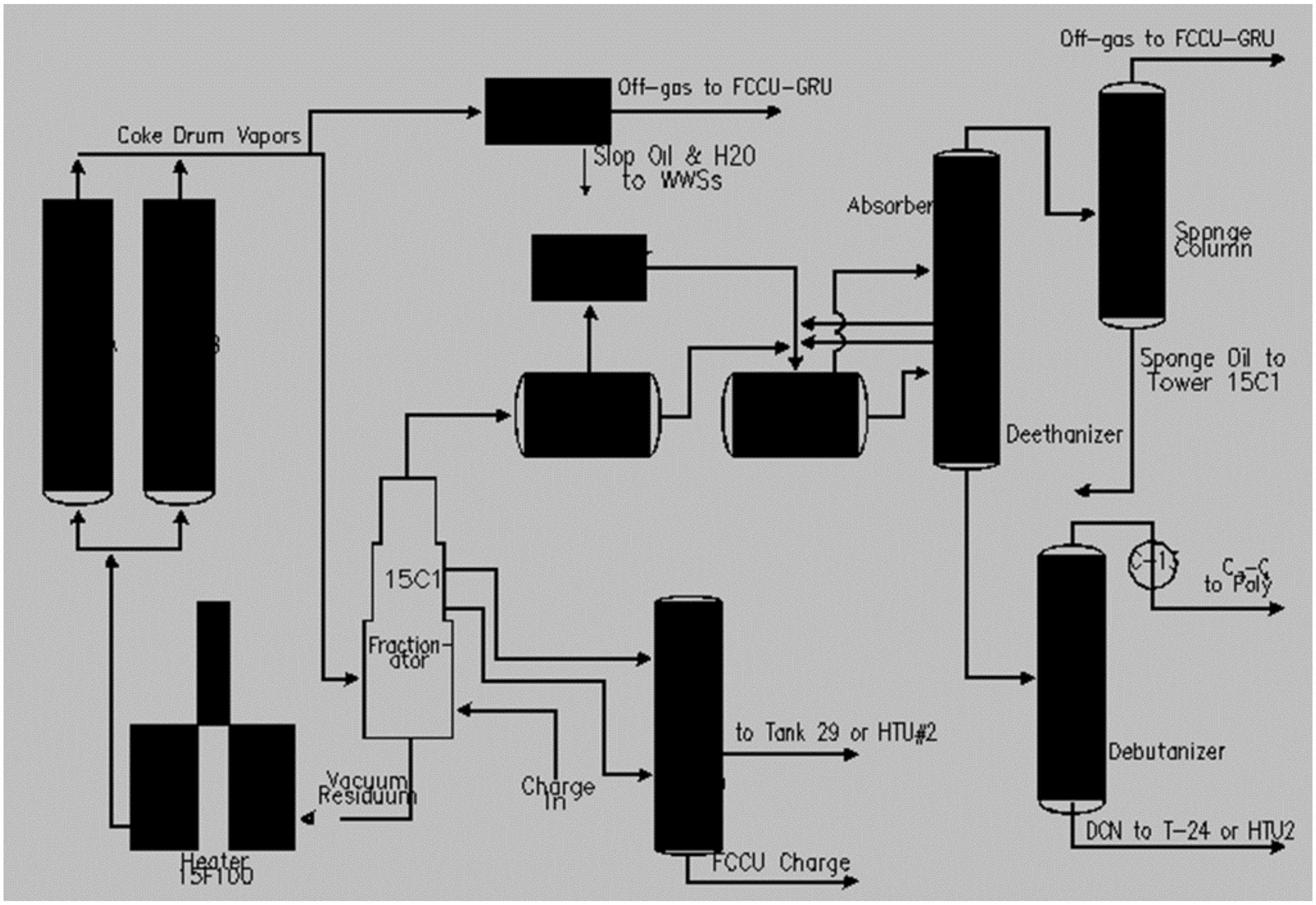



**Figure 4**

## Construction History and Regulatory Discussion

The DCU was constructed in 1984 under OAC 275 issued by the NWCAA on February 10, 1983. This OAC was revised on May 26, 1995 (revision a) to remove a firing rate limit on charge heater 15F-100 and instead set a 39.5 tons $NO_X$ per year limit and associated performance limit of 0.09 lb $NO_X$/MMBtu.

On September 30, 1997, the NWCAA issued OAC 628 for installation of a new burner in DCU Charge Heater 15F-100. OAC 628 was written to supersede OAC 275a. The new burner would increase the heater's firing rate capacity from 115 to 124 MMBtu/hour, which triggered NSPS Subpart J. On May 11, 1998, OAC 628 was revised (revision a) to include a light-ends recovery project at the DCU. The project triggered 40 CFR 60 Subpart QQQ requirements. OAC 628a has since been revised to OAC 628d (issued April 10, 2013) for non-construction-related regulatory applicability, compliance demonstration, and verbiage changes. Charge heater (15F-100) triggers 40 CFR 63 Subpart DDDDD as an existing unit designed to burn gas 1.

The RTR Initiative triggered requirements at the delayed coking units to depressurize coke drums to a closed blowdown system until the average vessel pressure or temperature meets the applicable limits. To meet these new applicable requirements, PSR has connected coke drum vents to an interlock system that will not allow the drum vents to open until the pressure in the top of the drum meets 2.0 psig or less to meet the new requirements added to 40 CFR 63 Subpart CC.

To address complaints regarding fugitive coke dust released during petroleum coke handling, the NWCAA issued Regulatory Order 14 that requires that all trucks hauling coke products to be covered and that the loading chute on the DCU coke hopper be modified to minimize coke free fall during loading. RO14 was revised to RO14a to remove deadlines that have passed.

## 3.3 Fluid Catalytic Cracking Unit (FCCU)

The FCCU is a 60,000 bpd unit used to convert heavy oils into a wide range of more usable petroleum materials. The feedstock is generally heavy distillate or gas oil produced at VPS or DCU. The FCCU consists of a catalyst section and a fractionation section, which includes the Gas Recovery Unit (GRU).

The catalyst section contains the reactor and regenerator, which, together with the standpipe and riser, form the catalyst circulation portion of the unit. The FCCU uses blowers to aerate and circulate the small spherical-shaped silica-alumina catalyst in a manner that allows it to behave as a fluid.

As the catalyst comes into contact with the oil, the long-chain hydrocarbons are broken into a wide range of smaller-chain materials that are routed to the fractionation section of the FCCU. During this oil-catalyst reaction process, the catalyst accumulates carbon, called coke that must be burned-off in the regenerator to reactivate the catalyst. This process of cleaning the catalyst generates sulfur dioxide due to the sulfur content of the coke. In addition, the regenerator can produce carbon monoxide (CO) depending on whether the unit is operating in full or partial combustion mode. In a partial combustion mode, the flue gases from regeneration contain large amounts of CO that must be combusted prior to release to the atmosphere. These flue gases are routed into two CO Boilers where combustion takes place to convert the CO to $CO_2$. The CO Boilers and wet gas scrubber (WGS) cannot be bypassed (the bypass stack was removed in March 2009). The combustion process produces heat for steam generation in the boilers. The boilers also have the capacity to burn supplemental gaseous fuels (i.e., refinery fuel gas) for additional steam production. The CO Boilers cannot fire solid or liquid fuels.

Particulate emissions are generated as the catalyst is degraded into smaller particles as a normal process in the FCCU. Primary catalyst removal occurs in the regenerator section in internal cyclones. The WGS, installed in 2005 replacing the electrostatic precipitator (ESP), is used as a control device to remove particulate matter and sulfur dioxide. The WGS is a non-venturi jet-ejector design.

As mentioned above, the fractionation section of the FCCU receives cracked hydrocarbon material from the reactor section. The cracked materials enter a fractionating column that separates the feed into naphtha and distillate streams. These are separated and routed to tankage or to the Hydrotreating Units for desulfurization. Fractionator bottoms (heavy oils) are used as ship fuel (bunker fuel). Light molecular weight materials are routed to the Gas Recovery Unit (GRU) section of the FCCU where C3-C4 materials are separated out and routed to the ALKY and CPU units for further processing. The C1-C2 materials are routed to the refinery's main fuel gas mix drum for distribution to combustion units throughout in the refinery.

Major components at the FCCU include the feed surge drums, air blowers, reactor, regenerator, main fractionator column, air compressors, CO Boilers, the WGS, and waste heat steam generators. Operating temperatures range from ambient to 1,375°F. Operating pressures range from –5 to 600 psi. Equipment and emissions units are identified in the process flow diagram below. The unit also has a number of components in heavy liquid, light liquid, and gaseous service that can emit fugitive VOC and HAP emissions.

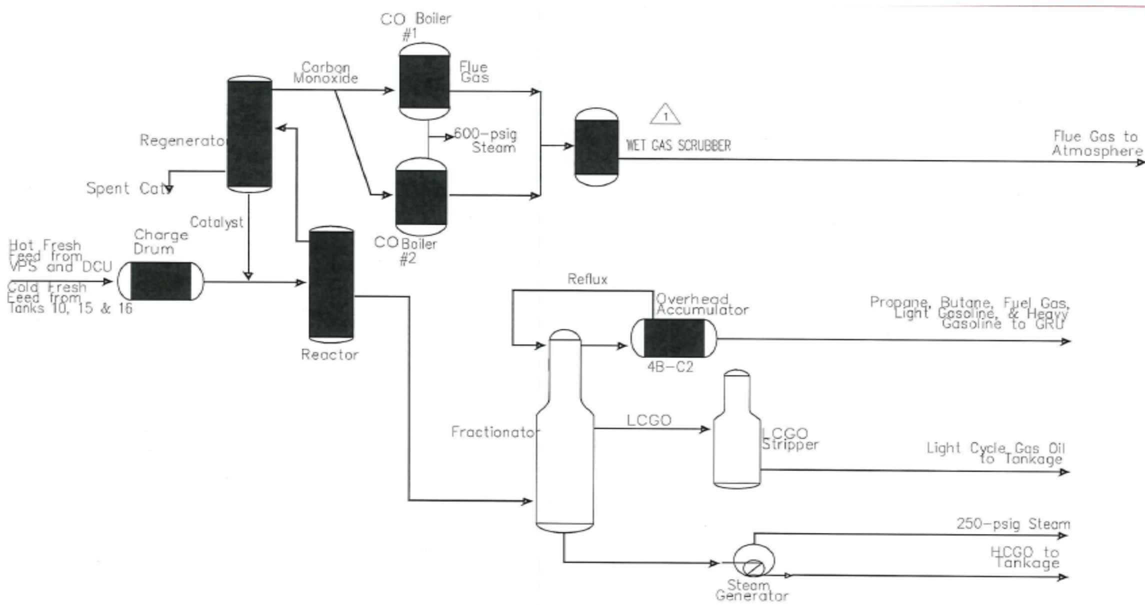



**Figure 5 Fluid Catalytic Cracking System**

## Construction History and Regulatory Discussion

The FCCU has a complex history of construction, modification and associated air permitting activity. OAC 623f currently represents the only valid applicable approval order for the FCCU. All others were either temporary in scope or have been superseded by more recent approval orders. Table 3-1 below summarizes construction and permitting activity for the FCCU in chronological order.

### Table 3 -1: FCCU Construction & Permitting History

| Date Approved | Approval | Description |
|---|---|---|
| 1958 | Grandfathered | Original FCCU construction |
| July 19, 1972 | OAC 74 (narrative) | Octane Improvement Project: Construct CO Boiler 2, CRU2, HTU2, ALKY2, East Flare, Tank 19 |
| April 11, 1985 | OAC 300 | Construct new fresh catalyst feed hopper at FCCU |
| September 19, 1988 | OAC 246 | FCCU modification |
| July 29, 1993 | OAC 361 | Construct ESPs on CO Boilers |
| March 18, 1994 | OAC 361a | Ammonia injection in ESPs |
| June 13, 1995 | OAC 361b | Removed requirement to establish a minimum catalyst feed rate, add requirement to establish a maximum sulfur dioxide mass emission limit |
| April 10, 1996 | OAC 361c | Require $H_2S$ instead of TRS monitoring of sulfur content of refinery fuel gas |
| February 23, 1998 | OAC 623 | FCCU vertical riser modification |
| June 17, 1999 | OAC 623a | Add PSD avoidance limits and establish offsets. Add references to Compliance Assurance Monitoring (CAM) and remove NSPS Subpart QQQ applicability |

| Date Approved | Approval | Description |
|---|---|---|
| July 9, 1999 | OAC 704 | Install 3 portable temporary diesel fired air compressors and diesel fuel tank for one year. |
| June 6, 2000 | OAC 704a | Extend temporary approval from one year to 15 months. |
| July 8, 2003 | OAC 623b | Substantial replacement of CO Boiler 1 tubes. Add a PSD-avoidance fuel gas firing rate limit and prohibit burning liquid fuel and sour water stripper gas (SWSG). Remove $SO_2$ monitoring requirement at FCCU regenerator. |
| January 5, 2005 | OAC 623c | Replace ESP with a wet gas scrubber (WGS). Remove: flue gas recirculation (FGR), DESOX catalyst, CEM on regenerator. Incorporated QQQ applicability. Undo changes in modification b due to postponement of boiler tube replacement. |
| April 8, 2010 | OAC 623d | Delete one-time tasks. Clarify: testing requirements, applicability of NSPS Subpart J, opacity test method. Remove terms the refinery in now incapable of. |
| July 12, 2012 | OAC 623e | Incorporate changes required due to Consent Decree. Update formatting, make report timing consistent with AOP requirements. Delete reference to bypass stack. Incorporate FCCU fresh catalyst hopper baghouse. |
| January 30, 2014 | OAC 623f | Clean up OAC, extract out Consent Decree requirements to be handled in a Compliance Order |

This table is included in this SofB to provide a brief history of the complex permitting surrounding the FCCU. Please see the SofB associated with the previous AOP for further detail regarding the historical permitting actions.

The FCCU, including the regenerator, and CO Boilers are potentially subject to 40 CFR 60 Subpart J (CO Boilers as fuel gas combustion devices and FCCU regenerator) and 40 CFR 63 Subpart UUU (catalytic cracking units). FCCU regenerators are potentially subject to particulate matter, opacity, CO, and $SO_2$ requirements under NSPS Subpart J. The PSR FCCU regenerator has been modified pursuant to NSPS and therefore triggered the NSPS Subpart J requirements for particulate matter, opacity, and CO but not for $SO_2$. In Paragraph 47(a) of the Equilon Consent Decree, PSR agreed that the FCCU regenerator is an affected facility for $SO_2$ under NSPS Subpart J. As such, the NWCAA issued Compliance Order (CO) 10 issued on February 12, 2014 that deemed that the FCCU regenerator is an affected source for $SO_2$ under NSPS Subpart J and must comply with the applicable requirements.

Pursuant to 40 CFR 60.104(b)(1), FCCU catalyst regenerators with add-on control devices have a choice to comply with either a 90% $SO_2$ reduction or a 50 ppmvd $SO_2$ at 0% $O_2$ emission standard on a 7-day rolling average, whichever is less stringent. OAC 623f Condition 7 and CO 10 Condition V.A requires that the FCCU WGS (i.e., the FCCU catalyst regenerator) meet, among other standards, a 50 ppmvd $SO_2$ concentration standard as well. As such, PSR has chosen to meet the concentration standard rather than the percent reduction limit.

As a petroleum refinery that is a major source for HAPs, PSR's catalytic cracking unit is subject to the requirements of 40 CFR 63 Subpart UUU, as an NSPS source. Subpart UUU has requirements to limit emissions of organic HAP (CO as surrogate) and metal HAP (PM and opacity as surrogate).

To calculate the lb PM per 1000 lb coke burn-off, Subpart J and Subpart UUU require that the catalyst regenerator exhaust be measured using a flow meter upstream of the CO Boilers. However, 40 CFR 63.1573(a) offers two alternatives for measuring the flow rate. PSR is measuring the inlet air flow rate to the catalytic cracking regenerator and continuously monitoring the carbon monoxide, carbon dioxide, and oxygen in the catalytic cracking regenerator exhaust to perform a material balance calculation that complies with (a)(2).

40 CFR 63 Subpart UUU was amended as part of the RTR initiative. New requirements in revised Subpart UUU included testing for particulate matter and hydrogen cyanide (HCN) emissions, installation of a COMS, selection of continuous parameter monitoring system (CPMS) to demonstrate compliance with HAP emissions during periods of startup, shutdown and hot standby and updates to the operation, maintenance, and monitoring plan (OMMP).

PSR completed HCN emissions testing June 29, 2017 and renewed their alternate monitoring plan (AMP) with EPA on September 9, 2019 which allowed them to demonstrate compliance with the revised visible emission standard by monitoring liquid-to-gas ratio correlated with annual performance testing, in lieu of installing a COMS. The CPMS compliance options PSR selected for periods of startup, shutdown and hot standby are maintaining oxygen concentration above one volume percent (dry basis) or one volume percent (wet basis) with no moisture correction. PSR will measure oxygen concentration in the exhaust gas from the catalyst regenerator using an existing $O_2$ monitor that has been used for calculating greenhouse gas emissions. Revisions to the FCCU OMMP to address CPMS during startup, shutdown and hot standby were submitted to NWCAA on March 23, 2018.

Also as part of the RTR initiative, new operating and pressure relief requirements and management of releases were added to Refinery MACT 1 for pressure relief devices (PRDs) that release to atmosphere. To meet these requirements, PSR has instituted three redundant measures to prevent the release to atmosphere and a mechanism to notify operations if there is a release from the 9 atmospheric PRDs on Main Fractionator Tower 3B-C1 at the FCCU.

Fuel gas combustion devices are potentially subject to $SO_2$ requirements under NSPS Subpart J. The PSR CO Boilers triggered NSPS Subpart J requirements for $SO_2$ and must therefore comply with the NSPS fuel gas requirements.

**CAM Plan:** As discussed above, the FCCU WGS is subject to an AMP to monitor liquid-to-gas (L/G) ratio in the scrubber to demonstrate compliance with the opacity standards in NSPS J and MACT UUU. This compliance demonstration can also demonstrate compliance with the State opacity standard. A minimum L/G ratio threshold was set during the initial WGS compliance test establishing the threshold needed to maintain compliance (compliance is based on a minimum value – a higher L/G ratio will provide better efficiency). An alarm is set at the minimum L/G ratio, which will alert personnel to perform corrective action.

The strategy for compliance monitoring proposed in the CAM Plan in SofB Appendix A to demonstrate continuous compliance with the grain per dry standard cubic foot (gr/dscf also referred to as grain loading) $PM_{10}$ limits is to rely upon the opacity liquid-to-gas ratio continuous monitoring. Due to the nature of the wet gas scrubber exhaust, setting the minimum L/G threshold for the AMP based on visible emissions was impossible so PSR set the minimum based on the gr/dscf limit.

The information in the CAM Plan was incorporated into the AOP terms in the MR&R column including descriptions of "excursion" and "exceedance" events, as appropriate. An excursion is a departure from an indicator range established for monitoring consistent with the averaging period specified for the monitoring. An excursion does not necessarily indicate that a permit limit has been exceeded and includes periods when significant periods of data collection are missed. An exceedance is an incident when emissions limits have been surpassed. In the case of the nature of the monitoring and averaging periods for the gr/dscf limits at the FCCU WGS, excursions are defined as the same as exceedances and the permit terms are written as such. That is, when the L/G ratio drops below the minimum L/G ratio set at the original source test (i.e., 0.93 gpm/mscfh on a 3-hour average), it is an exceedance of both the opacity limits and the gr/dscf $PM_{10}$ emission limits.

Note that the OAC-mandated annual source tests have demonstrated compliance with both the gr/dscf $PM_{10}$ emission limits and the lb/1000 lb coke burn-off limit. This testing allows for annual verification that the L/G monitoring set-point meets the emission limitations.

Pursuant to 40 CFR 64.6(c), the AOP Term mandates that the flow meters be maintained in accordance with the manufacturer's specifications. In addition, CAM requires that the permit term mandate the data availability of the monitoring system; similar to the requirement for CEMS in NWCAA Appendix A, the data availability during the monitoring periods was mandated to be greater than 90%. Exceedances of the minimum L/G ratio threshold must be reported in accordance with the breakdown and upset reporting provisions under AOP Term 2.4.8. In addition, monitoring data must be reported similarly to CEMS monitoring data in accordance with AOP Term 2.1.11.

## 3.4 Catalytic Polymerization and Nonene Units

### 3.4.1 Catalytic Polymerization Unit

The Catalytic Polymerization Unit (CPU) consists of a caustic treater section, a splitter section, reactor section, and product fractionation section. There are two caustic treating sections used to remove sulfur and reduced sulfur compounds – the unsaturated and saturated treater sections. The unsaturated treater section is charged with light feedstock that originates as a byproduct of cracking at the DCU and FCCU. This stream, which contains propane and butane as well as propylene and butylenes, also known as C3/C4 olefins, are first treated to remove reduced sulfur compounds ($H_2S$ and mercaptans). This stream is then sent to the splitter section to separate C3s from C4s. The C4 olefins are sent to the Alkylation (Alky) Unit and the C3 olefins are primarily routed to the reactor section of the CPU. Part of the C3 stream may be routed to the Alky2 Unit if required for alkylate production or CPU reactor switches. The saturated treater section is charged with propane and butane from HTU1 and VPS for sulfur removal and then sent to the depropanizer in the product fractionation section for separation into finished propane and butane. Sulfur-free propane and butane from the ISOM unit can also be sent to the CPU saturated treater section, if desired. The HTU2 has its own caustic treater and sends treated LPG to tankage via the LPG skid on the CPU.

In the CPU's catalytic reactors, propylene (C3) is passed through a solid phosphoric acid catalyst bed. The reaction converts C3s into a long chain product called polymer gasoline. Finally, the polymer gasoline is sent to depropanizer and debutanizer fractionation towers to separate out propane and butanes before sending the polymer gasoline to the Nonene Unit. Poly gasoline may also be routed to tankage for finished product blending.

Major components at the CPU include the treating section, splitter tower, reactors, depropanizer and debutanizer towers. Operating temperatures range from ambient to 450°F. Operating pressures range from 1 to 550 psi. Other activities that may result in emissions to the air are conducted periodically to properly operate and maintain the equipment.

### Construction History and Regulatory Discussion

The CPU was constructed during the 1976 Octane Improvement Project. The CPU was expanded as part of the 1998 Vertical Riser Project under OAC 623 (now OAC 623f). As such, it triggered 40 CFR 60 Subpart GGG.

The CPU is unique in that it does not have any process streams with HAP greater than 5% that would trigger 40 CFR 63 Subpart CC requirements for fugitive equipment leaks. However, the CPU does have two streams that qualify as Group 1 Miscellaneous Process Vents under Subpart CC, as the HAP content threshold for MPVs is lower than that for equipment leaks (20 ppm for MPVs versus 5% for equipment leaks). Therefore, leaking components are monitored and repaired as required by NWCAA 580.8 and Subpart GGG, which reference the LDAR program required under 40 CFR 60 Subpart VV.

### 3.4.2 Nonene Unit

The Nonene Unit produces nonene, a nine-carbon (C9) olefin compound that is used in the petrochemical industry. Poly gasoline from the CPU is used as feedstock for the Nonene Unit. In the Nonene Unit, the poly gasoline is separated and nonene and tetramer are recovered. Major components at the Nonene Unit include accumulator and stripper vessels, a railcar and truck loading rack, and three external floating roof tanks (80, 81 and 82). Because of the need to keep the nonene product from being contaminated, storage and transfer operations are conducted using equipment in dedicated nonene service.

Section 5 of the AOP includes specifically applicable regulations for the Nonene Unit. Because operations at the Nonene Unit fall into several functional groups, the process unit has been separated from the loading rack and storage tanks in the AOP. The nonene loading rack is listed under shipping & receiving and storage vessels listed under storage vessels.

#### Construction History and Regulatory Discussion

The Nonene Unit was constructed at the refinery in 1991 following issuance of Order of Approval 296 by the NWCAA on November 20, 1990. The project included three nonene storage tanks (Tanks 80, 81, and 82), fugitive components, truck rack and railcar loading, and oily water sewer drains. OAC 296 was revised to OAC 296a (issued April 12, 2013) to clarify federal rule applicability and add ongoing monitoring demonstration for railcar loading and storage tanks.

Note that the revised definition of "process unit" that includes loading racks in Subpart VV has been stayed. The "process unit" definition reverts to the previous definition that excludes loading racks. As such, the nonene loading rack is not subject to LDAR requirements under Subpart VV. Also, the nonene process (including the loading rack) is not subject to the LDAR requirements under NWCAA 580.8 because it does not utilize butane or lighter hydrocarbons as a primary feedstock. See SofB Section 3.10.3 for further discussion.

Because the Nonene Unit has a fairly pure feedstock and pure product, the unit does not handle materials with a HAP content large enough to trigger 40 CFR 63 Subpart CC (i.e., greater than 5% organic HAPs). As such, it is not subject to the equipment leak requirements or the overlap provision in 40 CFR 63.640(p). However, the Nonene Unit initial feedstock (i.e., polymer gasoline) contains HAPs; therefore, the nonene product has the potential to contain one or more of the listed HAPs under Subpart CC. As such, the nonene storage tanks (Tank 80, 81, and 82) are subject to 40 CFR 63 Subpart CC Group 2 storage vessel requirements. Also, an OAC limits the vapor pressure of the contents of the nonene storage tanks to less than 0.75 psia. As such, Tanks 80, 81, and 82 are not subject to 40 CFR 60 Subpart Kb or to NWCAA 560 and 580.3.

Construction of the nonene processing unit and nonene railcar and truck loading facilities involved the installation of new drains. Even though the Nonene Unit is a SOCMI unit under NSPS, because the Nonene Unit is located in a petroleum refinery, 40 CFR 60 Subpart QQQ applies to the Nonene Unit drains.

## 3.5 Catalytic Reforming Units (CRU)

Catalytic reforming converts low octane naphtha into high-octane blending stocks. In reforming, straight-chain hydrocarbons and cyclo-paraffins are converted to aromatics by dehydroisomerization and dehydrogenation. The naphtha feed from the hydrotreating units is mixed with hydrogen ($H_2$), vaporized and passed through a series of heaters and fixed bed reactors containing a platinum and rhenium bimetallic catalyst. The reactor effluent is sent to a separator where the pressure is reduced and the mixture cooled. Hydrogen and light hydrocarbons are separated from the higher molecular weight reformate, which is then fractionated.

The CRU1 heaters were shutdown in 2013 and have not been restarted. Portions of the old CRU1 are operating as part of the CPU and Isom unit. Isom reactor effluent is sent to a CRU1 separator where the pressure is reduced and the mixture cooled. Hydrogen and light hydrocarbons are separated from the higher molecular weight isomerate, which is then fractionated.

Hydrocarbon products for the CRUs are gas, LPG, and light and heavy platformate. The mostly-$H_2$ gas is compressed and recycled back to the Isom unit. The CRU1 section also uses jet fuel to sponge LPG from fuel gas for recovery in the hydrotreaters.

Major components at the CRU1 include Isom recycle compressor, product separator, and an absorber tower. One compressor (6DK1) is considered in hydrogen service.

Major components at the CRU2 include heaters, reactors, compressor, high and low pressure separators, low-pressure flash drum, stabilizer tower, platformate splitter tower, and C3/C4 splitter tower. Operating temperatures range from ambient to 980°F. Operating pressures range from 150 to 400 psi. One compressor (10PK101) is considered in hydrogen service.

Both units also contain a number of components in heavy liquid, light liquid, and gaseous service that can emit fugitive VOC and HAP emissions. Other activities that may result in emissions to the air are conducted periodically to properly operate and maintain the equipment. Note, however, there are no CRU bypasses.

CRU2 is semi-regenerative. The CRU catalyst is regenerated approximately once every year. During depressuring and purging, the flare is used for control. Internal caustic scrubbing is used to control HCl emissions during coke-burn off and catalyst regeneration.

### Construction History and Regulatory Discussion – CRU1

Note: The information regarding construction and regulatory applicability for CRU1 is retained for historic purposes, even though the heaters associated with the unit have been shutdown.

CRU1 was built with the original refinery construction in 1958. No significant modifications to the unit occurred until 1987 when all three of the original heaters were replaced with three new heaters having a common stack (Charge Heater (6D-F2), Interheater #1 (6D-F3) and Interheater #2 (6D-F4)). OAC 321 was issued by the NWCAA for this project on April 3, 1987. Based on this construction date, the heaters triggered 40 CFR 60 Subpart J as fuel gas combustion devices.

During NSR, BACT for $SO_2$ was determined to be equivalent to NSPS Subpart J, refinery fuel gas not to exceed 162 ppm $H_2S$ based on a 3-hour rolling average. Compliance was to be demonstrated using a CEM to continuously monitor $H_2S$ in the fuel gas to assure that the limit was not exceeded. In a July 7, 1988 approval letter, the NWCAA allowed PSR to monitor $H_2S$ in the refinery's main fuel gas drum. However, upon investigation it was found that CRU1 and

HTU1 run co-dependently and that most of the fuel gas combusted in these units is generated from within the CRU1/HTU1 units themselves. Because fuel gas from the CRU1/HTU1 is not being routed to the refinery's main fuel gas drum, monitoring $H_2S$ at that location was not considered representative of fuel gas being combusted at CRU1/HTU1.

On September 29, 1991, the NWCAA issued OAC 286 for construction of two new heaters with a common stack at HTU1 (7C-F4/F5). As Condition 4 of this order, the refinery was required to install a $H_2S$ CEM at the fuel gas drum that specifically services the CRU1/HTU1. On September 10, 1991, OAC 286 was amended to allow PSR to install a $SO_2$ monitor instead of the $H_2S$ CEM as originally planned. This change was facilitated with the amendment of Subpart J published on October 2, 1990 (55 FR 40175). The amended Subpart J allowed $SO_2$ monitoring of the heater exhaust gas in lieu of monitoring $H_2S$ in the fuel gas and established an equivalency between 20 ppm $SO_2$ in the heater exhaust to 162 ppm $H_2S$ in the fuel gas. The federal amendment was made in response to challenges encountered in $H_2S$ monitoring at that time.

Fortunately, installation of a $SO_2$ CEM at the HTU1 heater allowed the refinery to address the issue of monitoring NSPS Subpart J compliance with the fuel gas quality standards for the three new CRU1 heaters (6D-F2, 6D-F3 and 6D-F4). Because co-dependent CRU1/HTU1 units have a dedicated fuel gas mix system separate from the rest of the refinery, PSR was able to declare that $SO_2$ emissions at the HTU1 heater stack (7C-F4/F5) are indicative of those at CRU1 heater stack (6D-F2/F3/F4) thereby allowing the use of a single monitoring point to demonstrate compliance with the NSPS standard. This alternative monitoring strategy is allowed under 40 CFR 60.105(a)(3)(iv).

It should be noted that, in the rare and short-term event that the HTU1 is shut down while CRU1 continues to operate, there would be no $SO_2$ monitoring data to show compliance with Subpart J requirements. Because the CRU1 is operated with a catalyst bed that is poisoned by sulfur, only hydrotreated products having an extremely low sulfur content can be processed at the CRU. As a result, there would be little chance that the fuel gas generated at the CRU would have a $H_2S$ content of concern. The lack of $SO_2$ data that results from an HTU1 shutdown would be acceptable as long as it did not exceed the data acquisition criteria of NWCAA's Appendix A. If the loss of monitoring data exceeded the criteria in the appendix, it would be reported as an AOP monitoring deviation.

On May 26, 1995, OAC 321 revision "a" was issued to allow more operational flexibility for the three CRU1 heaters. This flexibility was afforded by removing a maximum firing rate limit on the heaters and instead relying on a 39.9 tons per year annual $NO_X$ emission limit and monthly reporting to assure that the PSD trigger of 40 tons was not exceeded. During NSR it was determined that PTE for all other pollutants were below PSD thresholds. On December 21, 1987, the 6D-F2, 6D-F3, and 6D-F4 common heater stack was source tested for $NO_X$ emissions resulting in 8.14 lb $NO_X$ /hour. Based on this source test the cumulative PTE for the three heaters is 35.63 tons per year and therefore below the 39.9 tons per year limit.

OAC 321b was issued on October 10, 2012 to incorporate applicability of NSPS Subpart GGGa due to Matheson hydrogen plant project and add ongoing compliance demonstration for $NO_X$ limit. This ongoing compliance demonstration is dictated by the future plans of the refinery for CRU1.

As discussed above, two of the primary purposes of CRUs are to generate hydrogen and create octane. With the advent of the mandate to use ethanol in gasoline, less octane is required to be directly generated from petroleum process itself. And with the construction of the neighboring hydrogen plant, the refinery has another source of hydrogen. As a result, PSR shut down the three CRU1 heaters April 12, 2013.

Because there is a remote chance that the unit may need to be restarted again due to changes in the political climate or issues at the hydrogen plant, PSR has stated that the unit will be maintained in such a fashion that it could be restarted. Because the heaters have been shut down for more than two years, the heaters are considered permanently shutdown and will need to go through new source review and get a new permit prior to restarting.

While the three heaters have been permanently shutdown, other parts of CRU1 are still in operation in conjunction with other process units, like the CPU and Isom, therefore the AOP still addresses applicable requirements for the remaining parts of the unit still in operation (vents, equipment leaks, etc).

**Excluded Conditions:** OAC 321b Conditions 1-4 require compliance with heater emission limitations (visible emissions, NOx, and compliance demonstration and reporting requirements). Because the heaters are permanently shutdown, these approval conditions are no longer applicable requirements and are not included in the AOP.

OAC 321b Condition 5 requires notification of initial startup of the added process equipment components (i.e., valves and pumps) due to the hydrogen plant project within 15 days after startup. PSR provided notification that the project commenced operation on March 10, 2013. This is a one-time requirement that has been completed and is not included in the AOP.

OAC 321b Condition 6 requires notification of the shutdown date of the CRU1 heaters within 15 days after shutdown. According to the PSR notification, the CRU1 heaters were shut down on April 12, 2013. As such, this portion of Condition 6 has been completed and is not included in the AOP.

## Construction History and Regulatory Discussion – CRU2

CRU2 was constructed as part of the 1976 Octane Improvement Project, which included Charge Heater (10H-101), Interheater #1 (10H-102), Interheater #2 (10H-103), and Stabilizer Reboiler (10H-104). Since original construction, there have been no significant modifications that would require NSR.

However, PSR worked on Interheater #2 (10H-103) in around 1985. As part of this project, a low-$NO_X$ burner was voluntarily installed. None of the other CRU2 heaters were modified. A construction permit was not issued for this project. All (3) heaters trigger 40 CFR 63 Subpart DDDDD as existing units designed to burn gas 1.

The light platformate section of CRU2 is regulated under a specialized LDAR program in accordance 40 CFR 61 Subpart J (Benzene NESHAP). However, the overlap provisions under 40 CFR 63.640(p) allows that equipment leaks subject to both 40 CFR 63 Subpart CC and other programs under 40 CFR 60 or 61 promulgated prior to September 4, 2007 need only comply with the Subpart CC requirements.

As part of the RTR initiative, emission limits and purging requirements were added to 40 CFR 63 Subpart UUU. Organic HAPs produced during depressurizing and purging operations are required to be routed to a flare that meets the control requirements developed as part of the RTR initiative. Inorganic HAPs from the catalyst regeneration flue gas vent are limited during coke burn-off and catalyst rejuvenation using both an emission limit and an operating limit. The emission limit is either a percent control or an outlet concentration value based on the type of catalytic reformer (e.g., semi-regenerating, cyclic, or continuous). The emission limit for CRU2 (and CRU1, when it was operating) is 30 ppmvd corrected to 3% oxygen. The operating limit is an operating parameter value established during the initial performance test.

CRU2 utilizes an internal scrubbing device to control HCl emissions during regeneration. As such, PSR is required to use colorimetric tube sampling system (i.e., Draeger tubes) to periodically measure the HCl concentration during regeneration to be averaged together to create a daily average. The operating limit is set using Equation 4 in 63.1567(b)(4)(iii), using the emission limit, the average from the Draeger tube testing during the initial performance test (or 1 ppmv, whichever is greater), and the tested HCl concentration in ppmvd corrected to 3% oxygen (or 1 ppmv, whichever is greater).

$$C_{HCl,ppmv\ Limit} = 0.9C_{HCl,AveTube}\left(\frac{C_{HCl,RegLimit}}{C_{HCl,3\%O2}}\right)$$

The initial performance test took place on October 3 and 7, 2005, the source testing and the Draeger tube testing for CRU2 (testing of CRU1 performed at the same time) all ended up less than 1 ppmv; so each parameter in the equation was set equal to 1 ppmv. Assuming these values, the operating limit is 27 ppmv.

## 3.6 Alkylation Units (Alky)

In the Alky units, low molecular weight olefins (C3/C4) are combined with isobutane using sulfuric acid as a catalyst in the reaction. The hydrocarbons and acid are mixed in a reactor called a contactor. Following reaction, the acid is separated from the resultant emulsion in a settler and the acid is returned to the contactor. The resulting product is called crude alkylate. The crude alkylate is treated with caustic to remove impurities such as trace acid, organic sulfates, and sulfonates. The treated crude alkylate is then fractionated to separate C4 and lighter hydrocarbon from the finished alkylate. The final alkylate is a high-octane and low RVP gasoline blending component.

General Chemical operates a sulfuric acid production plant located just east of the refinery under its own AOP. PSR trucks spent acid from the Alkylation Unit to General Chemical for regeneration.

Major components at the Alky1 include contactors, settlers, depropanizer, debutanizer, deisobutanizer, refrigeration compressor, and caustic washes. Operating temperatures range from −32 to 400°F. Operating pressures range from −5 to 200 psi.

Major components at the Alky2 include contactors, settlers, refrigeration compressor and four fractionators. Operating temperatures range from −32 to 400°F. Operating pressures range from 0 to 200 psi.

The Butadiene Hydrogenation Unit (BHU) is co-located at Alkylation Unit 1 and acts as a feedstock pre-treater for both Alky1 and Alky2. The BHU hydrogenates butadiene compounds that are found in the alkylation unit feedstock that originates from the FCCU and that comes off the splitter bottoms on the CPU. This stream goes to Tank 101, which feeds both Alky units. Hydrogenating butadiene in the feedstock is beneficial because then less sulfuric acid is required during alkylation processing.

### Construction History and Regulatory Discussion

Alky1 was built with the refinery in 1958. On July 12, 2004, NWCAA issued OAC 887 for the installation of a spare steam-driven flare drum pump at the Alky1 flare drum. The only expected emission increase was due to fugitive components subject to NSPS Subpart GGG, MACT Subpart CC, and enhanced LDAR. OAC 887a was issued on January 30, 2014 to clarify the leak detection and repair requirements.

Alky2 was constructed during the 1976 Octane Improvement Project and has had no significant NSR modifications since original construction. As a grandfathered unit, there are no applicable OACs for this process unit. However, the Alky2 includes both process vents and fugitive components and is subject to MACT Subpart CC requirements.

The BHU was constructed during the summer of 2001 and began operation on November 13, 2001. OAC 772 was issued for this unit on May 24, 2001, revised as OAC 772a on March 18, 2004, and revised again to OAC 772b on March 20, 2009. The OAC requires that an enhanced LDAR program be implemented at the BHU consistent with NSPS 40 CFR 60 Subpart VV standards (by reference through NSPS Subpart GGG and MACT Subpart CC) as modified with lower leak definitions as BACT.

## 3.7 Hydrotreating Units (HTU1, 2 & 3), Isomerization Unit, and Benzene Reduction Unit

### 3.7.1 Hydrotreating Units (HTU1, 2, & 3)

Hydrotreating Units 1 and 2 are charged with distillates and naphthas. HTU1 feed originates from the VPS whereas feedstock for HTU2 (which includes straight run and cracked feedstocks) originates from the VPS, FCCU and DCU. HTU3 treats gasoline products, mainly from the FCCU, prior to blending into final product. In general, hydrotreating removes unwanted sulfur and nitrogen contaminants from petroleum hydrocarbons. During the process, hydrocarbons are reacted with hydrogen under high pressure and in the presence of a catalyst. Hydrogen sulfide driven off in the reaction is treated and sent to the SRU via the amine system. Desulfurized hydrocarbon products are distilled to produce low octane naphtha, jet fuel, and diesel. The naphtha products from the HTU also serve as high quality feedstocks for the CRUs.

Major components at the HTU1 include the feed surge drum, heaters, reactor, high and low pressure separators, fractionator tower, JET and heavy straight run (HSR) sidecut strippers, fractionator overhead drum, and debutanizer. Operating temperatures range from ambient to 620 °F. Operating pressures range from ambient to 475 psi. Two compressors (7CK1 & 7CF2) are considered in hydrogen service.

Major components at the HTU2 include the feed surge drum, heaters, reactors, high pressure separator, low pressure flash drum, $H_2S$ stripper tower and accumulator, fractionators and accumulator, HSR sidecut stripper, and a treating section for light hydrocarbons. Operating temperatures range from ambient to 710 °F. Operating pressures range from ambient to 1000 psi. Three compressors (11PK101, 11PK102A, & 11PK102B) are considered in hydrogen service.

The third HTU was designed and built to remove sulfur from gasoline products (primarily cracked gasoline streams from the FCCU) thereby allowing the refinery to comply with future federal low sulfur gasoline standards. HTU3 uses a series of catalyst beds inside distillation columns to treat gasoline grade feedstocks sent over from the FCCU. The catalytic distillation process is specifically designed and operated to remove sulfur from the feed stock while minimizing the octane reduction normally resulting from saturating olefinic compounds prevalent in FCCU gasoline. As with the other HTUs, HTU3, for the most part, will generate most of the fuel gas needed to operate the combustion furnace in the unit. Any make-up fuel will be supplemented on an as-needed basis with gas from the refinery's main fuel gas mix drum or with purchased natural gas.

Major components of the HTU3 include the feed drum, CDHDS heater, CDHDS naphtha splitter and reflux drum, CDHDS tower and reflux drum, reboiler furnace, CDHDS hot and cold separators, $H_2S$ stripper tower and reflux drum, polishing reactor, polishing reactor hot and cold separators, naphtha splitter and reflux drum, recycle gas amine absorber, and vent gas amine absorber. One compressor (60K201) is considered in hydrogen service.

## Construction History and Regulatory Discussion – HTU1

HTU1 was built with the refinery in 1958.

**HTU1 Heaters (7C-F4 and 7C-F5):** The three original heaters were replaced in 1991 with two new heaters (7C-F4 and 7C-F5) having a common stack. The heater replacement project was approved by NWCAA on July 16, 1990 under OAC 286, which was modified in a letter from the NWCAA dated September 10, 1991 (referred to as OAC 286a). OAC 286b was issued on April 10, 2013 which updated the formatting, updated federal rule applicability, and added an ongoing compliance demonstration requirement. As a result of the construction date, heaters 7C-F4 and 7C-F5 triggered NSPS Subpart J.

OAC 286 set a BACT limit for $NO_X$ of 0.07 lb $NO_X$/MMBtu. This term originally had an initial testing requirement that was completed on June 9, 1993 (0.063 lb $NO_X$/MMBtu). Once it was completed, that requirement was removed from the OAC, leaving this condition without any ongoing compliance demonstration. BACT limits require an ongoing compliance demonstration; as such, during the most recent modification, the NWCAA included a $NO_X$ stack test that is required every five years.

Note that $NO_X$, CO, $PM_{10}$ and VOC emission reduction credits were granted for permanently shutting down the three original heaters (7C-F1, 7C-F2 and 7C-F3). Some of these credits, along with credits acquired from a permanent shutdown of Erie City Utility Boiler #3 were used to offset emission increases from the construction of March Point Cogeneration Company's Phase I and II projects to keep the projects from triggering PSD permitting requirements. Because these ERCs are more than 10 years old, whatever ERCs remain have expired.

Heaters 7C-F4 and 7C-F5 both trigger 40 CFR 63 Subpart DDDDD as existing units designed to burn gas 1.

**Fractionator Tower (7C-C5) Atmospheric PRDs:** As part of the RTR initiative, new operating and pressure relief requirements and management of releases were added to Refinery MACT 1 for pressure relief devices (PRDs) that release to atmosphere. To meet these requirements, PSR has instituted three redundant measures to prevent the release to atmosphere and a mechanism to notify operations if there is a release from the 5 atmospheric PRDs on Fractionator Tower 7C-C5 at HTU1.

## Construction History and Regulatory Discussion – HTU2

HTU2 was constructed during the 1976 Octane Improvement Project.

**Charge Heater (11H-101):** The Charge Heater (11H-101) has had no significant modifications that would require NSR since its original construction. Charge heater (11H-101) triggered 40 CFR 63 Subpart DDDDD as an existing unit designed to burn gas 1.

**Stripper Reboiler Heater (11H-102) and Fractionator Reboiler Heater (11H-103)**: On November 16, 1997, OAC 630 was issued allowing PSR to install higher capacity, low $NO_X$ burners in heaters 11H-102 ($H_2S$ stripper) and 11H-103 (fractionator). The modification increased the combined maximum firing rate of the heaters from 230 MMBtu/hour to 241 MMBtu/hour. On March 4, 2004, OAC 630a was issued to address construction of the ultra low sulfur diesel (ULSD) project at HTU2. OAC 630b was issued on March 10, 2009 to clarify the applicability of the equipment leak and wastewater requirements. As a result of these projects, HTU2 is subject to NSPS Subparts GGG and QQQ and heaters 11H-102 and 11H-103 triggered NSPS Subpart J. Both heaters 11H-102 and 11H-103 trigger 40 CFR 63 Subpart DDDDD as existing units designed to burn gas 1. HTU2 is also subject to 40 CFR 63 Subpart CC.

OAC 630c was issued on January 30, 2014 to move requirement to fire gaseous fuels to introduction, delete heater firing rate limit, clarify leak detection and repair requirements, and incorporate ongoing compliance demonstration with $NO_X$ limit.

## Construction History and Regulatory Discussion – HTU3

OAC 787 was issued January 20, 2003 for the construction of HTU3. Construction was completed in October 2003 with startup following shortly thereafter. The process unit includes a 95 MMBtu per hour Catalytic Distillation Technology Hydrodesulfurization (CDHDS) heater and associated hydrocarbon processing equipment.

In conjunction with the HTU3 project, PSR contracted with Air Liquide to construct a steam-methane reformer to supply hydrogen to the new hydrotreater. OAC 813 was issued to Air Liquide for their hydrogen plant on October 7, 2002 and provides the operating requirements for this separate facility. Although the facility is located within the boundaries of Puget Sound Refinery, it is permitted separately from PSR. It should be noted however, that because Air Liquide's hydrogen plant was constructed as a support facility for HTU3, the increased emissions from this plant were considered under in combination with the PSD analysis for HTU3.

Prior to completing construction of HTU3, OAC 787 was revised (revision a) to allow $SO_2$ emissions to be monitored using a stack CEM rather than a fuel gas $H_2S$ monitor. In March 2004, the OAC was again revised (revision b) because the CDHDS heater could not consistently meet the 6 ppm $SO_2$ (24-hour average) limit specified in the OAC 787a. This problem occurs not because of high sulfur in the hydrotreater fuel gas, but because of the hydrogen-rich nature of fuel gas being generated at HTU3. This hydrogen-rich flue gas effectively concentrates the $SO_2$ in the stack due to the fact that no $CO_2$ is produced during hydrogen combustion. The resulting combustion products are much lower in volume than for carbon-based fuel gas (methane, ethane, etc.).

OAC 787b issued on March 11, 2004, requires the CDHDS heater to meet a $H_2S$ limit for fuel gas burned at the heater with these limits based on NSPS (162 ppm) limits and BACT (50 ppm). OAC 787c, issued on March 10, 2005, lengthens the averaging time for the CDHDS heater rating due to variability in the heat content of the fuel gas resulting in a 12-month rolling average limit (62.2 MMBtu/hr) and an hourly average limit (124.4 MMBtu/hr). OAC 787d, issued May 25, 2005, increased the CDHDS heater rating with a 12-month rolling average limit of 95 MMBtu/hr and a 124.4 MMBtu/hr hourly limit. On April 17, 2009, the NWCAA issued OAC 787e to clarify the applicability of equipment leak and wastewater stream requirements.

OAC 787f was issued December 8, 2017 for modification of the HTU3 CDHDS bottoms reactor system so that produced gasoline meets EPA Tier III low sulfur gasoline specifications. The modification included changing out the four existing low NOx burners on the CDHSD heater (60F201) with six new ultra-low NOx burners, reducing the annual average heat rate capacity from 95 MMBtu/hr to 80 MMBtu/hr, along with addition of a new catalytic reactor and new stabilizer column. Ancillary support equipment was added during the modification, including one small compressor creating a new affected unit under 40 CFR 60 Subpart GGGa, twenty-two drains, creating a new individual drain system under 40 CFR 60 Subpart QQQ, and new equipment components in VOC service.

OAC 787g was issued May 15, 2018 to correct the effective date listed in the previous version. OAC 787f was issued stating the new OAC was effective upon issuance, and that the previous version was superceded. But PSR could not immediately make the modifications approved in OAC 787f, so it was reissued as OAC 787g with an effective date at the completion of the modification of the CDHDS bottoms reactor system.

During the second renewal of the AOP, an error was found in the visible emission method written into OAC 787g. PSR requested revision to correct the error and NWCAA administratively modified the permit to correct the typo, reissuing the permit as OAC 787h on May 5, 2021, with Condition 2 referencing Ecology Method 9A and removal of Condition 6, initial notification of startup, as this requirement had already been met.

CDHDS heater (6D-201) triggered 40 CFR 63 Subpart DDDDD as an existing unit designed to burn gas 1.

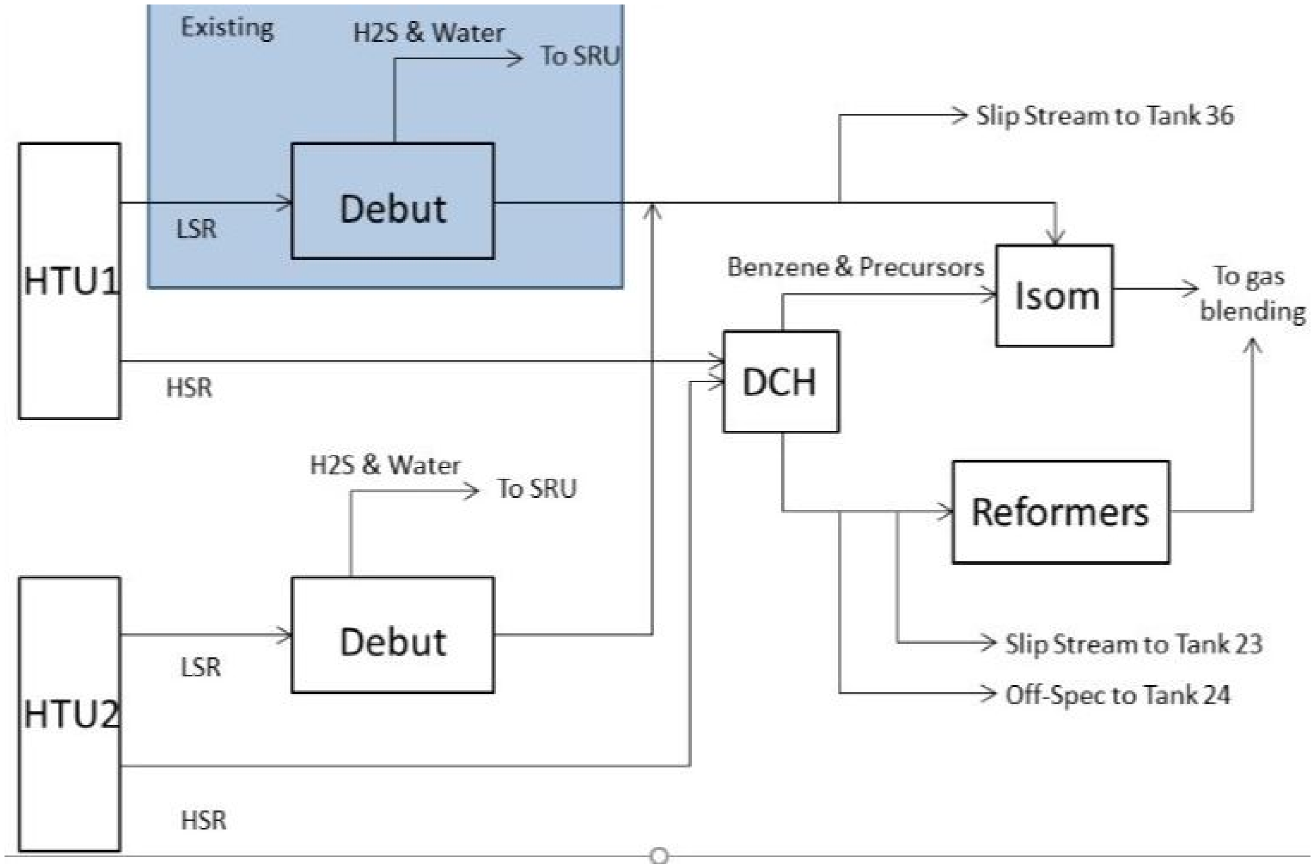
### 3.7.2 Isomerization Unit and Benzene Reduction Unit

The EPA regulation Mobile Source Air Toxics Rule 2 (MSAT2), published February 26, 2007, placed limits on the benzene content of gasoline, both reformulated and conventional. As of January 1, 2011, refiners had to meet an annual average benzene content standard of 0.62 vol% in gasoline. At PSR, the reformate streams are the largest contributors to the overall benzene content in gasoline, contributing 60 to 70% of the total benzene. The Benzene Reduction Unit (BRU) separates out benzene and benzene precursors (methylcyclopentane and cyclohexane), thereby reducing benzene in gasoline produced at PSR.

The ISOM Unit is located on the HTU1/CRU1 Unit. Light straight run (LSR) naphtha is received from HTU1 Debutanizer bottoms and HTU2 Debutanizer bottoms. The HTU2 Debutanizer column added during the BRU project removes butane, $H_2S$, and water from the HTU2 LSR naphtha stream. The $H_2S$ and water are contaminants to the ISOM catalyst and the butane is removed to reduce the volumetric load on the ISOM unit. The bottoms of the debutanizer column (i.e., pretreated LSR) are routed to the ISOM for benzene/benzene precursor removal. The HTU1 LSR naphtha stream is also a feed stream to the ISOM and is pretreated for butane, $H_2S$, and water removal through the existing HTU1 Debutanizer column.

Heavy straight run (HSR) naphtha is received from HTU1 and HTU2 into the decyclohexanizer (DCH) column where the HSR naphthas are combined and prefractionated into C5-C6 LSR naphtha (DCH overhead) processed in the ISOM unit and HSR naphtha processed in the CRUs. The DCH LSR naphtha stream contains most of the benzene and benzene precursors and is routed to the ISOM unit for further processing. The DCH HSR stream is routed to the CRUs, and since the benzene and benzene precursors have already been removed, no longer contribute to the benzene levels in the final CRU reformate product used in gasoline blending.

In the ISOM unit, hydrocarbon feed is mixed with electrolytic $H_2$ from the hydrogen plant header and then sent to the Benzene Saturation (Ben Sat) Reactor (6D-C29) to saturate, separate and remove benzene. The stream is then cooled to control the temperature to the inlet of the section to the isomerization reactor. The paraffins in the feed are then isomerized to increase the octane content. Downstream of the isomerization reactor, the effluent is cooled prior to flowing to the isomerization product separator. Excess hydrogen gas is removed from the reactor effluent in the separator and recycled back to the process while liquid product is routed to the isomerization stabilizer. The high octane bottoms product (Isomerate) from the stabilizer is cooled prior to being routed to tankage for gasoline blending.




## Figure 6 ISOM & BRU Process Flow Diagram

Major components at the ISOM Unit include two fractionation columns, two catalytic reactor vessels, one charge drum, one separator vessel, two overhead accumulation drums, associated heat exchangers, and the replacement of an existing accumulator drum with a larger drum. Heat for the ISOM Unit is provided by steam; no new heaters were installed as part of the ISOM Unit.

The BRU consists of a single large fractionation column, the DCH column, with ancillary equipment including a charge drum, accumulator drum, thermosiphon reboiler, fin-fan condensers and rundown cooler, heat exchangers, pumps and a flare knock out drum. The HTU2 Debutanizer column and ancillary equipment was also installed as part of the BRU.

## Construction History and Regulatory Discussion

Note that the highest benzene content stream in the refinery is the feed into the BenSat Unit, with a 5.5 wt% benzene. Because this is less than the 10 wt% applicability threshold, 40 CFR 61 Subpart J does not apply.

In 2004, OAC 883 was issued for the construction of the ISOM Unit. The only source of emissions in the ISOM Unit is fugitives from components (i.e., valves, pressure relief valves, pumps, flanges, and sample stations). The ISOM Unit is subject to NSPS Subpart GGG, NSPS Subpart QQQ, and MACT Subpart CC.

The ISOM must also comply with BACT for equipment leaks as enhanced LDAR requirements. The Isom Unit began operation on January 19, 2006.

PSR submitted an application for OAC 883a to remove the reference to 40 CFR 60 Subpart QQQ, which PSR states does not apply due to the overlap provisions in 40 CFR 63 Subpart CC. The NWCAA denied this modification because the overlap provisions state that, should a stream be subject to both Subpart QQQ and Subpart CC, the source need comply with Subpart CC, not that Subpart QQQ does not apply. OAC 883b was issued on January 30, 2014 to clarify the leak detection and repair requirements.

On July 22, 2009, the NWCAA issued OAC 1045 for the construction of the Benzene Reduction Project (BRP), which included the decyclohexanizer (DCH) column and the HTU2 debutanizer. The project triggered 40 CFR 60 Subpart GGGa for equipment leaks, 40 CFR 60 Subpart QQQ for process drains, and is subject to 40 CFR 63 Subpart CC for equipment leaks.

**Excluded Conditions:** 40 CFR 63 Subpart CC (63.640(p)) includes overlap provisions for equipment leaks. The version of Subpart CC at the time of OAC 1045 issuance (May 25, 2001) stated that equipment leaks that are subject to Subpart CC and to 40 CFR parts 60 and 61 are required to comply only with Subpart CC. As such, even those equipment leaks subject to potentially more stringent 40 CFR 60 or 61 requirements in the future (e.g., 40 CFR 60 Subpart GGGa promulgated November 16, 2007) must only comply with Subpart CC. The NWCAA believed that the BRP should comply with the more stringent requirements in Subpart GGGa regardless of the overlap provisions in Subpart CC; hence, OAC 1045 Condition 1 was written to that effect. However, Subpart CC was modified on October 28, 2009 to include a statement that equipment leaks subject to Subpart GGGa are required to only comply with Subpart GGGa. As such, OAC 1045 Condition 1 is no longer necessary and is not included in the AOP.

OAC 1045 Condition 2 requiring written notice of the completion of the Benzene Reduction Project is complete is not listed in the AOP because it is a one-time requirement that has been completed. The BRP started operation on April 5, 2011.

## 3.8 Sulfur Recovery Unit (SRU)

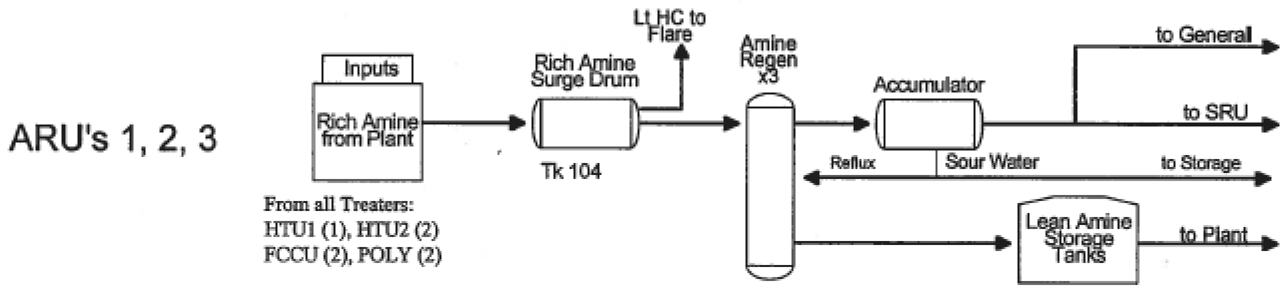
The Sulfur Recovery Unit (SRU) converts $H_2S$ to liquid elemental sulfur. Sulfur is collected from process streams around the refinery through an amine treatment system that uses diethanolamine (DEA) to absorb $H_2S$ from fuel gas and liquefied petroleum gas (LPG) streams: six to remove $H_2S$ from fuel gas and four to remove $H_2S$ from LPG streams via contactors. The six fuel gas absorbers are dedicated to specific process units: FCCU; DCU (located at FCCU); FGR; HTU1; HTU2; and HTU3. $H_2S$ in the fuel gas is absorbed into the amine solution in the absorbers. The absorber towers also have internal packing and trays to improve contact efficiency between gas streams and the lean amine for $H_2S$ absorption.

As the lean DEA in both absorbers and contactors becomes saturated with $H_2S$ (becomes rich), it must be regenerated back to a lean state to regain its affinity for $H_2S$. Amine regeneration occurs in the amine regeneration unit (ARU), located adjacent to the CPU, using steam to drive $H_2S$ out of solution. This concentrated amine acid gas is sent to the sulfur recovery units for control, while the lean amine is collected in storage tanks for recirculation in the amine treatment system. All three ARUs operate on a continuous rich-lean header system that run in parallel and on a continuous cycle.

Three wastewater strippers located at the FCCU remove $H_2S$ and ammonia from sour wastewater collected from various process units. Sour gas off the strippers is combined in the overhead condenser and routed to the sulfur recovery units for sulfur removal.

The $H_2S$ enters the SRU in the amine acid gas (AAG) and sour water gas feeds.

## Figure 7 Amine Treatment System Flow Diagram




PSR has two parallel SRUs (SRU3 and SRU4) with capacities of 150 LTPD and 170 LTPD, respectively. Each SRU is comprised of thermal reactor, catalyst beds and condensers, and tail gas treating unit (TGTU 1 and 2) and incinerator. Each SRU can normally handle the full refinery sulfur load thereby improving the overall reliability of the SRU system and reducing acid gas flaring incidents. This allows the refinery to handle higher sulfur loads resulting from increased hydrodesulfurization of intermediate product streams to produce lower sulfur fuels as required by recent federal regulation.

In the Claus section, $H_2S$ in the AAG and sour water gas feed is partially converted to $SO_2$ through controlled, sub-stoichiometric combustion in the SRU thermal reactors. The $H_2S$ and $SO_2$ then react to form elemental sulfur and water. The off-gas is cooled and the sulfur condenses to a liquid. The remaining gases are reheated and passed through a series of catalyst beds and condensers to increase the conversion to elemental sulfur. Sulfur recovered in SRU3 is routed directly to two sulfur storage tanks. Sulfur recovered in SRU4 is collected in a dedicated sulfur pit, then is transferred to sulfur storage tanks. Conversion from $H_2S$ to elemental sulfur in the Claus section of the SRU is about 98%. This allows the refinery to process crude oil with a higher sulfur content into finished products with a low sulfur content. The resulting liquid sulfur is sold as a commodity chemical product.

In addition to converting $H_2S$ to elemental sulfur, the Claus reactors destroy ammonia in the sour water gas feed to nitrogen ($N_2$) gas. Any VOCs carried with the sour water gas are also destroyed. An approximate operating temperature of 2700°F is required to destroy the ammonia gas.

Any remaining $H_2S$ and $SO_2$ in the tail gas not recovered in the catalyst and condensers is sent to the TGTU for final scrubbing. Here all remaining sulfur species are converted back to $H_2S$. This $H_2S$ is then absorbed as it comes in contact with a MDEA (methyldiethanolamine) solution in the amine absorber. The absorbed $H_2S$ creates a rich MDEA mixture that is regenerated using steam. At the MDEA regenerator, concentrated $H_2S$ is liberated and the $H_2S$ stream is sent to the SRU thermal reactors for reprocessing. Conversion from $H_2S$ to elemental sulfur for the Claus section and TGTU combined is estimated at 99.99%. The gases leaving the absorber overhead contain small amounts of residual $H_2S$, which are combusted in incinerator stacks for full conversion to $SO_2$ before they are emitted to the atmosphere.

For contingency purposes, the main acid gas line to the SRU can be diverted to the flare system. Also, if necessary, the Claus section effluent can bypass the TGTU and go directly to the incinerator.

Major components at the SRU include two thermal reactors, waste heat boilers, condensers, catalytic reactors, two incinerator stacks, quench tower, amine stripper tower, amine absorber tower, and a MDEA storage tank. Operating temperatures can reach 2700°F. Process operating pressures are generally below 5 psig. Steam generator pressures on the steam side can reach 600 psig.

Major components at the ARUs include a regeneration tower, overhead accumulator, rich amine surge drum, and lean amine storage tanks. Operating temperatures range from ambient to 400°F. Operating pressures range from 5 to 250 psi.

## Construction History and Regulatory Discussion

On February 27, 1981, the NWCAA issued OAC 255 for the construction of two 25 long tons per day (LTD) Claus sulfur recovery units (Units 1 and 2). OAC 255a was issued on March 9, 1989 to allow an expansion of production of Units 1 and 2.

On June 17, 1999, the NWCAA issued OAC 693 for a modification to the SRU to add a third SRU train (SRU3), increasing facility production to 175 LTD. The modification is linked to the FCCU Vertical Riser Project (OAC 623c) in regard to the PSD netting analysis.

On May 5, 2003, NWCAA issued OAC 828 for the construction of SRU4. Construction of a new unit would improve the overall reliability of the SRU, reduce acid gas flaring, and allow the refinery to handle higher sulfur loads. OAC 828 superseded OAC 693 upon startup of the SRU4 on November 9, 2004. The existing Claus Units 1 and 2 were decommissioned on June 23, 2005, within twelve months of startup of the new unit.

Due to the construction dates, the SRU3 and SRU4 both triggered 40 CFR 60 Subpart J as fuel gas combustion devices because they use refinery gas as supplemental fuel in Claus sulfur recovery plants. Note that Condition 1 limits supplemental fuel to natural gas except during periods of natural gas curtailment.

OAC 828 was modified to OAC 828a (issued on April 17, 2009) to clarify sulfur pit emission operation, delete $NO_X$ and CO emission limits (initial testing completed and compliance demonstrated), along with cleanup.

OAC 828a was modified to OAC 828b on September 4, 2018 to allow PSR the ability to comply with an $SO_2$ BACT limit which had originally been set based on the NSPS J $SO_2$ limit of 250 ppmvd at 0% $O_2$ on a 12-hour rolling average basis, but as allowed in 60.100(e), could be met by complying with the $SO_2$ limit in NSPS Ja. Revisions to NSPS Ja resulting from the RTR initiative provide calculated adjustment to the $SO_2$ emission limit for SRUs that operate oxygen-enriched to the Claus burners. As both SRU3 and SRU4 operate oxygen-enriched, this modification was approved in the modified OAC.

Higher $SO_2$ concentrations occur from oxygen-enriched SRUs because when oxygen is added (enriched) to the intake air for the Claus burner, it changes the ratio of nitrogen to oxygen found in the air entering the burner. In an oxygen-enriched system, there is a lower proportion of nitrogen to oxygen (i.e., 50% nitrogen to 50% oxygen) than that found in ambient air (~ 79% nitrogen and 21% oxygen). Unlike oxygen, nitrogen is not consumed in the SRU reactions. Instead, nitrogen is largely passed through, unreacted. Less nitrogen entering the SRU means there will be less nitrogen diluting the exhaust gas. Therefore, assuming the same total inlet gas flow rate, $SO_2$ concentration in the exhaust gas of an SRU with oxygen-enrichment will be higher.

To demonstrate compliance with the oxygen-enrichment adjusted $SO_2$ limit, PSR uses a continuous emission monitoring system (CEMS) to measure and record $SO_2$ at the incinerator stacks, and a continuous parameter monitoring system (CPMS) to measure and record the volumetric gas flow rate of ambient air and oxygen-enriched gas supplied to the Claus burner and calculates the hourly average $O_2$ concentration of the air-oxygen mixture. This $O_2$ concentration is then used to adjust the $SO_2$ emission limitation to account for the oxygen-enrichment. PSR began implementing the oxygen adjustment for the SRUs January 30, 2019.

Also, because the SRUs use refinery fuel gas as a supplemental fuel, the SRUs also qualify as fuel gas combustion devices under NSPS Subpart J; to comply, fuel gas $H_2S$ concentration is monitored at the main fuel gas mix drum.

With the RTR initiative, new requirements during startup and shutdown required monitoring of the incinerator firebox temperature and outlet oxygen concentration in the exhaust gas, as well as updates to the operation, maintenance and monitoring plan.

There are certain lines in the SRUs that have a VOC content greater than 10% by weight. As such, and due to the construction dates, the SRU3 and 4 triggered the LDAR requirements under 40 CFR 60 Subpart GGG. Also, because diethanolamine (DEA) is a listed HAP, there are lines in the SRU with a HAP content greater than 5% by weight; therefore, the SRU is subject to the LDAR requirements in 40 CFR 63 Subpart CC.

Because OAC 828b Condition 6 applies to $SO_2$ emissions from the entire refinery, it is included in AOP Section 4 rather than the SRU portion of the AOP Section 5. OAC 828b is the only OAC currently applicable to the SRU.

**Excluded Conditions:** OAC 828b Condition 10 requires notification of completed installation of meters necessary to perform $SO_2$ adjustment calculation. Notice was provided February 1, 2019. This is a one-time requirement that has been completed and is not included in the AOP.

## 3.9 Utilities

The utilities area provides steam, cooling water, and electrical services to the refinery. The utilities area is divided into four sections: Erie City boiler, cogeneration units (including Cogen cooling tower), stand-by wharf generator, and refinery cooling towers.

### 3.9.1 Erie City Boiler

Erie City Boiler is rated at 390 MMBtu/hr, can fire natural gas and refinery fuel gas, and provides steam to refinery units. In addition, the Boiler House area (BOHO) provides operations with pneumatic air, boiler feedwater, fire water and service water. The Erie City Boiler is the only boiler operating in this process area. There are no emissions to the atmosphere released from steam use. Three stationary reciprocating internal combustion engines (RICE) reside in the Boiler House area, which are discussed in SofB Section 3.12.

#### Construction History and Regulatory Discussion

The Erie City Boiler was built with the original refinery construction in 1958. Since that time there have been no modifications to the boiler triggering NSR or NSPS requirements. With promulgation of the Boiler MACT (40 CFR 63 Subpart DDDDD), the Erie City boiler became subject as an existing unit designed to burn gas 1.

Note that another Erie City Boiler (#3) was permanently shut down as a condition of OAC 475. This shutdown allowed emission reduction credits to be granted for the construction of the Cogens thereby allowing the project to avoid PSD for $NO_X$ under creditable offsets.

### 3.9.2 Cogeneration Facility

Three General Electric Frame 6 cogeneration units (Cogens) built in 1990/1991 are nominally rated at 40 MW each which generate electricity for sale to the grid and steam for the refinery. Each turbine is equipped with a heat recovery steam generator (HRSG) with a 200 MMBtu/hr duct burner. The turbines generate 600 psi steam, approximately 300,000 pounds per hour of steam total. The units normally burn about a 70:30 mix of natural gas and refinery fuel gas from the FCCU but also have the ability to burn propane, and butane. The duct burners can only fire natural gas or refinery fuel gas. Figure 6 is a simplified flow diagram of the Cogen fuel gas system.

The cogeneration unit also includes a steam turbine and a cooling tower. The steam turbine receives excess 40 psi steam from the refinery and generates electricity for sale to the grid. The cooling tower was constructed for use by the cogens in 1990. Hexavalent chromium was never used in the cogen cooling tower; as such, the cogen cooling tower is not subject to 40 CFR 63 Subpart Q.

The turbines are equipped with steam injection and selective catalytic reduction (SCR) with ammonia injection for $NO_X$ control. Sulfur dioxide is controlled by the selection of low sulfur fuels. Pipeline grade natural gas, propane, and butane are very low in sulfur. The reduced sulfur compounds in the refinery fuel gas are reduced by means of an amine scrubbing system to meet the hydrogen sulfide concentration limits imposed for fuel gas combustion devices in 40 CFR 60 Subpart J. Particulates, carbon monoxide, volatile organic compounds (VOC's), and toxic air pollutants are controlled by the selection of clean burning fuels and maintaining good combustion.

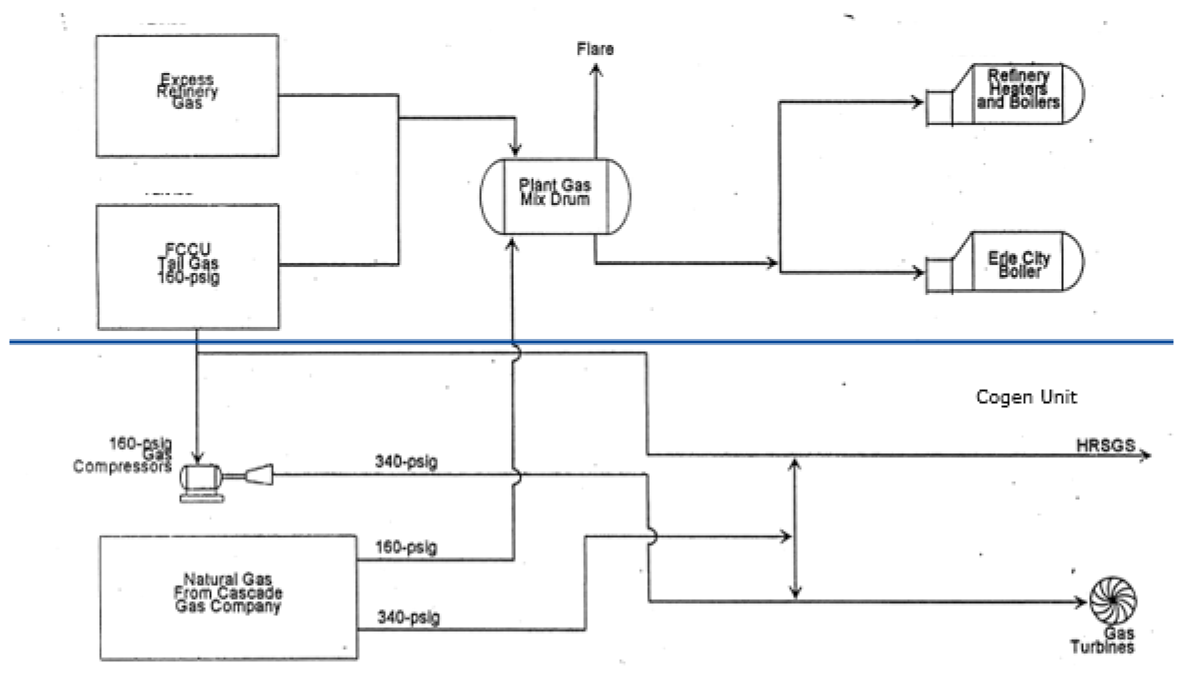



**Figure 8 Cogen Fuel Gas Utility Simplified Flow Diagram**

## Construction History and Regulatory Discussion

The facility was originally owned and operated by the March Point Cogeneration Company (MPCC). On February 1, 2010, Shell PSR took ownership of the cogeneration units. Note that a change in ownership is not a trigger for NSPS; as such, even though the cogens may maintain potentially affected sources in refinery-specific NSPS (e.g., oily water sewers under Subpart QQQ and equipment leaks under Subpart GGG or GGGa), they did not trigger the NSPS standards just due to the ownership change.

The facility was constructed in two phases. Phase 1 involved the construction of Cogens 1 and 2 (OAC 475 issued October 26, 1990). Commercial operation began in November of 1991.

OAC 475 did not initially require the installation of a selective catalytic reduction (SCR) system to control $NO_x$. There was some consideration that General Electric was developing a low $NO_x$ system that could achieve similar $NO_x$ reductions without the use of SCR with ammonia injection. Three years were granted to install equipment that would meet the final BACT standard. Subsequently, an SCR system was installed instead of a low $NO_x$ combustion system. The SCR system was installed in July of 1993. During the first three years of operation the $NO_x$ limit was higher, and there was no requirement for ammonia injection. The original OAC 475 was revised in March 17, 1994 (OAC 475a) to impose more stringent $NO_x$ limits and to establish a limit for ammonia emissions.

OAC 476 for Phase 2 was issued August 7, 1991. Phase 2 involved the construction of Cogen 3. Selective catalytic reduction was installed from the outset. Best Available Control Technology for $NO_x$ was slightly more stringent for Phase 2 than Phase 1. Unit 3 began operation in December 1993.

Emission offsets from the permanent shutdown of Erie City Boiler 3 were used during the permitting of all three Cogens to avoid triggering PSD.

There have been several revisions to the original OACs for both phases to clarify ambiguous language, establish averaging periods, establish exemptions from emission reporting during periods of startup and shutdown and remove the allowance to burn av-jet and low sulfur distillate fuel. OAC 475i (Cogens 1 & 2) and 476h (Cogen 3) (both issued June 13, 2018) are the most recent versions and are reflected in the AOP.

**OAC 475i & OAC 476h Ammonia CEMS RATA:** OAC 475i and 476h require that ammonia emissions from each stack be monitored using CEMS. Note that ammonia is a state toxic air pollutant and not a pollutant subject to federal requirements. The CEMS are required to be certified in accordance with 40 CFR 60 Appendix B and operated in accordance with 40 CFR 60 Appendix F, NWCAA 367, and NWCAA Appendix A. However, there is no Performance Specification for ammonia under 40 CFR 60 Appendix B; because ammonia is used to control $NO_X$, Performance Specification 2 for $NO_X$ is used.

The Relative Accuracy (RA) in a $NO_X$ RATA is the measure of accuracy of the CEMS operation and is defined as the sum of the absolute average difference between the Reference Method (RM) and the CEMS readings (|d|) and the 2.5% confidence coefficient (CC) divided by a certain value depending on the measured emissions relative to the standard. When emissions are greater than half of the standard, the denominator is to be the average of the RM values when emissions and the RA must be less than 20%. When emissions are less than half of the standard the denominator is to be the Emission Standard (ES) and the RA must be less than 10%. When emissions are extremely low (i.e., getting down into the noise), small variability in the CEMS readings from the RM can cause the RATA to fail. To address this, the NWCAA has approved a third option for the calculation of RA that is similar to that offered in Performance Specification 4A for CO. In this case, when emissions are less than half the standard (i.e., 5 ppm) as measured by the Reference Method, the RA is calculated only by adding (|d|) plus CC, and the RA must be less than 2 ppm. This option is gap-filled into the AOP using NWCAA's sufficiency monitoring authority.

**OAC 475i & OAC 476h Opacity:** Opacity emissions from the turbine stacks shall not exceed five percent (5%) for more than six minutes in any one hour period as determined by EPA Method 9. When the turbines are firing gaseous fuels, ongoing compliance with this standard is demonstrated using the general opacity monitoring listed in AOP Section 6.1.

**40 CFR 60 Subpart Db Nitrogen Oxides Requirements – Duct Burner:** The duct burner is subject to a $NO_X$ limit of 0.20 lb/MMBtu on a 30-day rolling average (60.44b(a)(4)(i)). Initial compliance is demonstrated either with a performance test under 60.8 or use of a temporary CEMS for 30 days. The CEMS sampling site may be located at the outlet of the steam generating unit but the measured $NO_X$ emissions shall be compared against the emission limit for the duct burner (60.46b(f)(2)).

For ongoing compliance, Subpart Db generally requires installation of a $NO_X$ CEMS. However, duct burners subject to the $NO_X$ limits are not required to install a $NO_X$ CEMS or keep corresponding records (60.48b(h)). EPA Applicability Determination Index entries PS15 and 9700102 agree with this interpretation that only the initial compliance demonstration is required and no ongoing compliance demonstration is mandated. Because the initial compliance demonstration allows for a CEMS on the steam generating unit outlet to demonstrate compliance, the ongoing compliance demonstration for the purposes of the AOP is the $NO_X$ CEMS on the turbine stack as required by OAC 475i and 476h.

**40 CFR 60 Subpart GG Nitrogen Oxides Requirement – Emission Limit:** The turbines are subject to 40 CFR 60 Subpart GG. Subpart GG contains a $NO_X$ limit for subject turbines based on the following equation (40 CFR 60.332(a)(1)):

$$STD = 0.0075 \times \frac{14.4}{Y} + F$$

where:

*STD* = allowable ISO corrected (if required under 60.335(b)(1)) $NO_X$ emission in percent by volume dry at 15% oxygen

*Y* = manufacturer's rated heat rate at manufacturer's rated load in kJ/W-hr

= firing gaseous fuels: 11.2 kJ/W-hr (10,560 Btu/kW-hr LHV)

*F* = $NO_X$ emission allowance for fuel-bound nitrogen (referred to as an F-value)

ISO conversion under 60.335(b)(1) is optional because the units are equipped with add-on control technology – steam injection and SCR. PSR does not to correct for ISO standard conditions to determine compliance with the $NO_X$ limit, which is consistent with the OAC limits as well.

According to 40 CFR 60.332(a)(3), sources may accept an F-value of zero or may determine an appropriate F-value through fuel sampling or manufacturer's analysis. PSR has chosen to accept an F-value of zero. If PSR chooses to utilize an F-value that is greater than zero, sampling would be required in accordance with 40 CFR 60 Subpart GG.

Assuming an F-factor of 0, the allowable $NO_X$ concentration firing gaseous fuels is 96 ppmvd at 15% oxygen which is listed in the AOP. For units with CEMS, excess emission events, and hence the emission limits, are based on four-hour averages (40 CFR 60.334(j)(1)(iii)(A)).

The turbines are able to fire other fuels as well (e.g., propane, butane). However, gaseous fuels are the primary fuels; the liquid fuels are used rarely and only as supplemental fuels so are not explicitly listed. The $NO_X$ limits for the liquid fuels can be calculated using the NSPS equation if desired. In addition, note that the NSPS limits are significantly greater than the other limits imposed through new source review.

**40 CFR 60 Subpart GG Nitrogen Oxides Requirements – Monitoring:** 40 CFR 60 Subpart GG requires daily monitoring of the fuel nitrogen content if an F-value greater than zero is assumed (40 CFR 60.334(h)(2)). MPCC requested to EPA that they be excused from the daily monitoring of nitrogen content because they continuously monitor $NO_X$ emissions using a CEMS. EPA Region 10 granted relief from this monitoring requirement in a letter dated October 19, 1992 contingent on the operation of the $NO_X$ CEMS. However, since PSR is assuming an F-factor of zero, the daily monitoring is not required. As such, this requirement is not listed in the AOP.

**40 CFR 60 Subpart J Sulfur Dioxide Requirement – Emission Limit:** As fuel gas combustion devices, the turbines are subject to the 40 CFR 60 Subpart J $SO_2$ limit of 20 ppmvd at 0% $O_2$ on a 3-hr rolling average (40 CFR 60.105(a)(3)(iv)). Turbines generally operate at, and turbine-specific emission limits are to be corrected to, 15% oxygen. As such, for ease of compliance, this limit was converted to 15% oxygen as follows:

$$conc_A = conc_B \times \left(\frac{20.9 - A\%O_2}{20.9 - B\%O_2}\right)$$

where:

$conc_A$ = concentration (ppmvd) at A percent oxygen

$conc_B$ = concentration (ppmvd) at B percent oxygen

Therefore, 20 ppmvd at 0% $O_2$ is equivalent to 5.6 ppmvd at 15% $O_2$. The limit averaging period does not change. Note that this limit is more strict than the 3-hour limit mandated by BACT under new source review (i.e., OAC 475i and 476h).

**40 CFR 60 Subpart GG Sulfur Dioxide Requirements – Monitoring:** 40 CFR 60 Subpart GG requires periodic monitoring of the fuel sulfur content to demonstrate continuous compliance with the sulfur standard (40 CFR 60.334(i)). Because the Cogens regularly fire refinery fuel gas, which does not meet the definition of natural gas in the rule, the sulfur content of the refinery fuel gas must be determined and recorded daily. MPCC requested to EPA that they be excused from the daily monitoring of sulfur content because they continuously monitor $SO_2$ emissions using a CEMS. EPA Region 10 granted relief from this monitoring requirement in a letter dated October 19, 1992 contingent on the operation of the $SO_2$ CEMS.

**LDAR:** PSR took ownership of the Cogens on February 1, 2010; there was no need for a physical modification as part of this transition. As such, the Cogens became part of a "petroleum refinery" and potentially subject to all the rules that apply only to petroleum refineries. However, pursuant to 40 CFR 60.14(b)(6), a change in ownership does not qualify as a modification under NSPS; therefore, the Cogens did not trigger the LDAR requirements under 40 CFR 60 Subpart GGG or GGGa.

In addition, the Cogens fire both natural gas and a fuel gas stream off the FCCU; they are not engaged in petroleum refining to produce transportation fuels. As such, the Cogens do not qualify as "petroleum refining process units" under 40 CFR 63 Subpart CC so the Cogen equipment leaks are not an affected source. Also, no testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems under 63.640(d)(5). Therefore, the Cogens are exempt from the LDAR requirements under 40 CFR 63 Subpart CC.

**Cooling Tower:** The Cogen cooling tower did not use chromium-based treatment chemicals as of August 12, 1993; therefore, it is not subject to 40 CFR 63 Subpart Q.

The cooling towers at the Cogen are used for boiler feedwater; the facility has no heat exchangers in organic HAP service (i.e., having at least 5 wt% of listed HAPs). As such, 40 CFR 63 Subpart CC for heat exchangers does not apply.

### 3.9.3 Cooling Towers

For the refinery, there are two wet cooling towers used to cool process water at the refinery by providing direct contact between the cooling water and the air passing through the towers. They are located just northwest of the SRU. The cooling water does not directly contact the process hydrocarbon stream, instead it is circulated through process unit heat exchangers where heat can either be added or removed from hydrocarbon products through the use of non-contact heat exchangers. The cooling towers can be a source of VOC emissions to the atmosphere if leaks develop in cooling water heat exchangers or condensers. Heat exchanger leaks are regulated in 40 CFR 63 Subpart CC.

Cooling Tower 1 was constructed during original refinery construction in 1958. Cooling Tower 2 was installed with the 1976 Octane Improvement Project. Pursuant to the heat exchanger requirements in 40 CFR 63 Subpart CC, hydrocarbon contamination is monitored in the riser pipe in each cooling tower. This requirement is addressed in the AOP under each process unit that maintains subject heat exchangers rather than under the cooling towers.

Hexavalent chromium was originally used as a biological growth inhibitor in the cooling water but was phased out from use by PSR in the 1980s. As such, the refinery cooling towers are not subject to 40 CFR 63 Subpart Q.

## 3.10 Receiving, Pumping, and Shipping

Often referred to as RP&S, Receiving, Pumping and Shipping is broken down into six specifically regulated areas within the refinery:

- Gasoline/Diesel Truck Loading Terminal
- Diesel Railcar Loading Rack
- Nonene Truck and Railcar Loading Rack
- Ethanol Unloading and Storage
- Propane/Butane Railcar Load Rack (LR-2) & LPG Truck and Railcar Loading Rack (LR-3)
- Marine Terminal
- PSR Feedstocks Import (PFI)
- Coke loading

Coke loading activities are specifically regulated under a regulatory order (RO 14a). Because these operations are located at the DCU, they are listed in the AOP and the SofB under the DCU.

### 3.10.1 Gasoline/Diesel Truck Loading Terminal

The gasoline/diesel truck loading terminal has a dispensing rack with the capacity to load up to four cargo tanks at a time which was part of the original refinery construction in 1958. In 1993, the rack was upgraded to add automated loading controls and lock-out systems and, in accordance with NWCAA 580.4, retrofitted with a control device to control the emissions of gasoline vapors displaced during loading. Originally in OAC 380 (dated August 17, 1992), PSR proposed to use a carbon absorption system; however, PSR decided to install a John Zink (ZTOF) Vapor Combustion Unit as the control device (OAC 380a dated April 30, 1993). The ZTOF unit is supplied with natural gas as an auxiliary fuel. OAC 380b has since been revised to OAC 380c (issued April 10, 2013) for non-construction-related regulatory applicability and verbiage changes.

There are a number of overlapping regulations that apply to the gasoline/diesel truck loading terminal. These include: NWCAA 580.4 because the terminal loads more than 7,200,000 gallons of gasoline annually, WAC 173-491-040(2) because the terminal loads more than 7,200,000 gallons of gasoline annually and is located in an ozone attainment area, and 40 CFR 60 Subpart XX because the terminal was modified after December 17, 1980. In addition, as of 1998, Refinery MACT 1 regulations apply a modified version of 40 CFR 63 Subpart R for gasoline terminals. Also, for those loading terminals that are subject to both 40 CFR 60 Subpart XX and Refinery MACT 1, they need only comply with the Refinery MACT 1 requirements. As such, specifically applicable regulations cited in the AOP only include those in Subpart R that are specifically called out as applicable in 40 CFR 63.650 (Subpart CC). Note that Subpart R references requirements in Subpart XX.

Because the Gasoline/Diesel Truck Loading Terminal contains or contacts material that is at least 5 percent by weight total organic HAP, it is subject to the equipment leak provisions in 40 CFR 63 Subpart CC. In addition, the truck rack is also potentially subject to 40 CFR 60 Subpart GGG. However, the Subpart GGG definition of process unit does not include loading racks as affected sources; therefore, the load rack is not subject. Note, that the truck rack must also comply with the monthly visual inspection required under 40 CFR 60 Subpart XX. This visual inspection allows the use of sight, smell and audio clues to find leaks.

40 CFR 63 Subpart CC, via reference to 40 CFR 63 Subpart R (National Emission Standards for Gasoline Distribution Facilities [Bulk Gasoline Terminals and Pipeline Breakout Stations]), makes a distinction between "thermal oxidizers" and "flares". A thermal oxidizer is defined as "a combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize hazardous air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures." A flare is defined as "a thermal oxidation system using an open (without enclosure) flame." Because the ZTOF unit utilizes an enclosed flame that has a stack where it can be tested, EPA considers it to be a thermal oxidizer and it must be regulated as

such, including monitoring firebox temperature under 40 CFR 63.427(a)(3) (see the preamble to the modification to 40 CFR 63 Subpart R in 68 FR 70962).

PSR conducted vapor combustor source tests on October 15, 2009 and October 18, 2011 pursuant to 40 CFR 63.425(b)(1) during which the firebox temperature was continuously monitored. Based on these testing data, the minimum firebox temperature was 85°F on a 5-minute block average. Automatic interlock devices are in place to prevent loading unless appropriate thermal oxidation temperatures are met and to assure that the tanks loaded all have a valid leak tighten test certification on record. Note that all cargo tanks are assumed to be in non-dedicated service and therefore displaced vapors are controlled whether loading gasoline or diesel.

Because the vapor combustor combusts hydrocarbon gas generated at the refinery and was built after June 11, 1973, it was determined that the truck rack vapor combustor is a fuel gas combustion device subject to 40 CFR 60 Subpart J.

To demonstrate compliance, PSR submitted an alternative monitoring plan to EPA for monitoring $SO_2$ emissions from the thermal oxidizer to show compliance with 40 CFR 60 Subpart J requirements, which was approved on December 4, 2001.

### 3.10.2 Diesel Railcar Loading Rack

On February 5, 2001 the NWCAA issued OAC 757 for construction of a diesel railcar loading rack. OAC 757 has since been revised to OAC 757a (issued March 20, 2009) for non-construction-related regulatory applicability, compliance demonstration, and verbiage changes.

Because the Diesel Railcar Loading Rack does not contain or contact material that is at least 5 percent by weight total organic HAP, it is not subject to the equipment leak provisions in 40 CFR 63 Subpart CC. In addition, the railcar rack is also potentially subject to 40 CFR 60 Subpart GGG. However, because of the Subpart GGG definition of process unit, loading racks are not affected sources; therefore, the load rack is not subject. As such, the Diesel Railcar Loading Rack does not have any LDAR requirements.

**Excluded Conditions:** OAC 757a Condition 4 that requires the Diesel Railcar Loading Rack meet ambient air toxics requirements in accordance with WAC 173-460. This condition is not listed in the AOP because a screening analysis was completing during NSR and therefore there is no on-going requirement.

### 3.10.3 Nonene Loading Rack

On November 20, 1999, the NWCAA issued OAC 296 for construction of a nonene processing unit, nonene storage and loading rack. Because the nonene processing, storage, and loading are all located in different areas of the refinery, the nonene processing and storage are listed in different parts of the AOP. OAC 296 has since been revised to OAC 296a (issued April 12, 2013) for non-construction-related regulatory applicability, compliance demonstration, and verbiage changes.

The Nonene Loading Rack is potentially subject to 40 CFR 60 Subpart VV as a SOCMI unit. However, because of the Subpart VV definition of process unit, loading racks are not affected sources; therefore, the load rack is not subject. Also, because the Nonene Loading Rack does not contain or contact material that is at least 5 percent by weight total organic HAP, it is not subject to the equipment leak provisions in 40 CFR 63 Subpart CC. As such, the Nonene Loading Rack does not have any LDAR requirements.

### 3.10.4 Ethanol Unloading and Storage

On July 22, 2009, the NWCAA issued OAC 1046 for construction of an ethanol unloading and storage project to allow blending of ethanol into gasoline during loading into trucks. This project included an internal floating roof storage tank (Tank 85) and installation of new and repurposing existing fugitive components. Because the storage tank is located at the gasoline truck rack, the entire ethanol unloading and storage project is considered part of RP&S and addressed in AOP Section 5.10.4.

Because this project included only an ethanol storage tank and associated fugitive components, it is not considered part of a refinery production unit. As such, it is not considered part of a "process unit" under the current definition and is not subject to the LDAR requirements under 40 CFR 60 Subpart GGGa. The inclusion of Subpart GGGa in the nonbinding introduction of OAC 1046 is incorrect.

Due to the construction date, size, and a vapor pressure greater than 0.75 psia, the ethanol storage tank is subject to 40 CFR 60 Subpart Kb. However, because the ethanol vapor pressure is less than 1.5 psi, it is not subject to NWCAA 560/580.

In addition, although the ethanol is denatured using 5 wt% gasoline or natural gasoline, the denaturant is not all HAP. As such, the Ethanol Unloading and Storage project is not subject to the LDAR requirements under 40 CFR 63 Subpart CC. Therefore, the Ethanol Unloading and Storage unit is not subject to LDAR requirements.

With natural gasoline or unleaded gasoline as the denaturant, the denatured ethanol storage tank contains or contacts one or more of the HAPs listed in Table 1 of 40 CFR 63 Subpart CC (e.g., benzene, toluene). As such, it is subject to 40 CFR 63 Subpart CC storage tank requirements. Because the denatured ethanol does not have an annual average HAP liquid concentration greater than 4%, Tank 85 is considered a Group 2 storage vessel. These are further reasons why this tank is not included with the rest of other tanks in Section 5.14 of the permit.

**Excluded Conditions:** OAC 1046 Condition 2 requires written notification of completion of the Ethanol Unloading and Storage project within 15 days after completion. PSR provided notification that the project commenced operation on July 6, 2010. This is a one-time requirement that has been completed and is not included in the AOP.

### 3.10.5 Marine Terminal

The marine terminal was constructed with the original refinery in 1958 and there have been no modifications since that time triggering NSR. As such, no OACs or NSPS regulations apply to the marine terminal.

Because the marine terminal is 0.5 miles or more from shore, it is exempt from 40 CFR 63 Subpart Y requirements, including LDAR, but, pursuant to 63.560(d)(6), must meet the submerged fill requirements under 40 CFR 153.282. Because the marine terminal does not meet the applicability criteria of Subpart Y, it is not subject 40 CFR 63 Subpart CC for marine loading or LDAR.

### 3.10.6 Propane/Butane Railcar Load Rack (LR-2) & LPG Truck and Railcar Loading Rack (LR-3)

The Propane/Butane Railcar Load Rack and the LPG Truck and Railcar Loading Rack were built with the refinery in 1958 and there have been no modifications since that time triggering NSR. Generally, handling propane is a non-regulated activity so there are no specifically applicable regulations that apply. However, NWCAA 580.8 requires an LDAR program for components handling VOC at process units and loading sites which utilize butane or lighter hydrocarbons as a primary feedstock. The affected process units are alkylation, polymerization, and LPG loading. As such, the Propane/Butane Railcar Load Rack and the LPG Truck and Railcar Loading Rack are subject to the LDAR requirements under NWCAA 580.8.

Note, however, that the current version of NWCAA 580.8 (amended March 13, 1997) includes the LPG loading process unit. The version of the rule included in the SIP (December 13, 1989) states that affected process units are alkylation, polymerization, and light ends units, which excludes LPG loading. As such, the NWCAA 580.8 term in the AOP for LPG loading only includes the State only version of the rule and does not reference the federal version in the SIP.

### 3.10.7 PSR Feedstocks Import (PFI)

On April 13, 2015, PSR began receiving intermediate feedstocks via a dual-sided, seven-rail car, closed-loop, unloading station approved in OAC 1181, issued June 12, 2014. Railcars are heated by non-contact steam upon arrival at the station to allow material to reach a temperature and viscosity that allows it to gravity drain out of the railcar. Unloading hoses are connected in parallel to the bottom of each railcar, which collects material into a large collection pipe for pumping to existing tankage.

OAC 1181a was issued July 11, 2018, allowing receipt of lighter crude feedstocks through the PFI rail unloading, which would be routed to existing tankage or directly to the units for processing. No changes to the existing closed-loop unloading system were made to accommodate this revision.

**Excluded Conditions:** OAC Condition 1181a Condition 4 requires written notification of the date PSR starts to receive lighter feedstock at the PFI. PSR provided notification that the receipt of lighter feedstocks commenced November 29, 2018. This is a one-time requirement that has been completed and is not included in the AOP.

## 3.11 Flares

Three elevated flares operated in a cascading flare design, each with its own water seal pot to prevent gas breaking through to the flare unless there is a pressure increase in the flare header (i.e., a release), are used to combust waste gases at the refinery. During normal operation, liquid and gaseous hydrocarbons are recovered by compressors operated to maintain 0.5 psig pressure in the flare header. These flare gas recovery (FGR) compressors, installed in 2006 as part of the Hydrocarbon Flaring Study under the Equilon Consent Decree, take suction off the flare header upstream of the seal pots, allowing up to 300 mscf/hr of flare vent gas and liquid hydrocarbons to be recovered and treated for removal of $H_2S$ before being burned as fuel gas in combustion units throughout the refinery. The FGR unit consists of five compressors rated at ~ 60 mscf, each, two separator vessels, a fin-fan cooler and amine absorption tower (located at the DCU) to reduce sulfur content prior to reuse of recovered gas in fuel-fired equipment around the refinery. The FGR system has reduced flaring volumes and decreased sulfur emissions from flaring events.

The FGR compressors are set up to auto-start and auto-stop to maintain flare header pressure at 0.5 psig in response to changes in gas rates routed to the flare from process units. However, unexpected increases in flare header pressure (i.e., releases) may occur that the FGR system cannot instantaneously respond to and break-through at the seal pot(s) may occur. During a release, the east flare seal pot water level is set to breakthrough when header pressure exceeds ~1.0 psig, allowing relief of flare gas through to the east flare tip. If the pressure is not adequately relieved through the east (primary) flare, the water seal pot levels on the north and south flares (secondary flares) will breakthrough when header pressure exceeds ~ 1.4 psig, allowing relief through the secondary flares, as well.

All three flares are located northeast of the refinery's process unit are. The east flare has a smokeless capacity of 234 mlb/hr when using 50 mlb/hr of 225 psi steam @ 525° F. The north and south flares each have smokeless capacities of 120 mlb/hr when using 38 mlb/hr of steam. Baseline flare flow for the north and south flares are 1 mscf/hr, each; baseline flow for the east flare is 6 mscf/hr. Total baseline flare flow at the refinery is 8 mscf/hr or 192 mscf/24-hr.

All three flares are equipped with steam injection at the flare tip to create the turbulence needed to enhance mixing of flared hydrocarbon gas with ambient air for better combustion and reduce or avoid smoking (visible emissions). Steam rate is automatically controlled to respond to changes in flare vent gas volume to meet net heating value minimum of 270 btu/cf during flaring episodes and minimize visible emissions. A mass flow meter located on the flare header combined with a video camera directed at each flare tip assists operators in monitoring flare system operation and make adjustments to avoid visible emissions.

## Construction History and Regulatory Discussion

The North and South Flares were constructed as part of the original refinery in 1958. The primary East Flare was constructed as part of the Octane Improvement Project in 1972.

**North and South Flares:** The north flare tip was replaced in 2014 and inspected in 2019 with new thermocouples installed. The south flare tip was replaced in 2019. The replacements were considered "in-kind" replacements performed as part of routine repairs for the flares. Tip replacements are not modifications under NSPS Ja or Refinery MACT 1 because flare capacity does not increase. Tip replacements also do not trigger NSPS reconstruction as the cost of the tip replacement is well below the 50% threshold for the cost of a new flare.

**East Flare:** The east flare tip was replaced in 2017. The tip was manufactured by Zecco Engineering, and has the same capacity and performance as the previous tip. The new flare tip continues to be steam-assisted but now includes steam ejectors that pull steam and air into the combustion zone (perimeter air). A velocity seal is used to conserve the amount of purge gas needed to safely prevent air backflow down the stack. As noted above, tip replacements are not considered modifications under the NSPS Ja or Refinery MACT 1, nor are they considered reconstruction under NSPS.

A design analysis was completed on the flares and submitted to the NWCAA as part of the source's Refinery MACT 1 Initial Notification of Compliance Status Report submitted January 1999. The report satisfied the initial performance test requirements for each flare in accordance with 40 CFR 60 Subpart A (60.18) and 40 CFR 63 Subpart A (63.11). The analysis was required because the refinery uses the flares as control devices for Refinery MACT 1 Group 1 process vents and for control of leaks from pump seals regulated under Refinery MACT 1 equipment leaks in HAP service.

Following the RTR revisions, after January 30, 2019, flares subject to the provisions of 40 CFR §60.18 or §63.11 and Refinery MACT 1 are only required to comply with Refinery MACT 1 per the overlap provisions in §63.640(s). Revisions to Refinery MACT 1 to reduce emissions of organic HAPs include requirements and monitoring for flares used as control devices at sources subject to Refinery MACT 1 found in §63.670 and §63.671. At PSR, these sources are: group 1 miscellaneous process vents (MPVs), leaks from equipment (pump seals) in HAP service routed to a flare control device, and pressure relief devices (PRDs) routed to a closed vent system. In addition, flares receiving gas from the fuel gas system shall meet the requirements for flare control device.

As part of the new RTR initiative, flares used as control devices required upgrades to operational equipment, installation of monitoring equipment, tracking of operational parameters and alarms for operational limits. To meet these requirements, PSR installed a BTU analyzer, calorimeter, vent gas flow meters, steam flow meters, supplemental gas flow meters, digital monitoring video equipment, and auto ignition systems. PSR was also required to develop a continuous parameter monitoring system (CPMS) plan, outlining how each of the monitoring devices are managed and maintained, as well as supplement their flare management plan (RMP), required under NSPS Subpart Ja. A copy of the most recent FMP incorporating requirements for minimizing emissions from flaring during startup, shutdown, or emergency releases, required in §63.670(o)(1), was submitted to NWCAA January 30, 2019. A copy of the CPMS plan was provided to NWCAA October 29, 2020.

As part of Equilon Consent Decree negotiations, Shell PSR accepted that the flare system at PSR had been modified and, as such, was subject to 40 CFR 60 Subpart J as a fuel combustion device. The compliance date for the PSR flare system to come into compliance was December 31, 2012. However, 40 CFR 60 Subpart Ja was promulgated with flare requirements on June 24, 2008. With the construction of the Benzene Reduction Project, the flare system was modified and thereby triggered Subpart Ja on April 5, 2011. Note that because the flare was subject to Subpart J prior to triggering Subpart Ja, it must comply with the Subpart Ja $H_2S$ standards upon modification.

Flares under NSPS Subpart Ja are considered independent affected sources rather than fuel gas combustion devices. NSPS Subpart Ja requires flared gas be limited to 162 ppmv $H_2S$ on a 3-hr average basis. Process upset gases and fuel gas released to the flare as a result of relief valve leakage or from an emergency malfunction event are exempt from this limit. PSR monitors flare gas $H_2S$ to demonstrate compliance with NSPS Subpart Ja. The NSPS Subpart J and Subpart Ja 162 ppmv $H_2S$ limits are essentially equivalent.

NSPS Subpart Ja also requires that the refinery: develop and implement a flare management plan; conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet per day (scfd) above the baseline flow in a 24-hour period, or contains sulfur that, upon combustion, will emit more than 500 pounds of $SO_2$ in a 24-hour period by continuously monitoring flare flow and the sulfur content in flare gas. As such, PSR has installed and maintains a flare flow meter and total $SO_2$ monitor on the flare. If the $SO_2$ is emitted from flaring during a planned refinery startup or shutdown, the root cause analysis and corrective action is not required but the discharge must be recorded and reported.

NSPS Subpart Ja generally allows three years from the date of promulgation (i.e., a compliance date of November 11, 2015) to demonstrate compliance with new requirements, such as the flare management plan or conducting root cause analyses. However, as flares that were subject to NSPS Subpart J that subsequently triggered NSPS Subpart Ja, the PSR flares are currently subject to the 162 ppmv $H_2S$ on a 3-hour rolling basis limit under NSPS Subpart Ja (compliance date as of November 13, 2012) rather than the requirement under NSPS Subpart J. NWCAA received the original FMP submitted by PSR November 12, 2015. The FMP was later updated to include requirements identified in §63.670(o)(1) and was submitted to NWCAA January 30, 2019.

A sweet hydrogen stream bypasses the flare gas recovery system but is combusted in the flare (see OAC 918a). This excess hydrogen stream is generated when the hydrogen generators (i.e., catalytic reforming units, isomerization unit) make more hydrogen than the hydrogen consumers (i.e., hydrotreating units) can use. However, this stream does enter the flare system upstream of the flow and sulfur monitors; therefore, it does not bypass the sulfur monitoring and does not need to be addressed as an inherently low sulfur stream under NSPS Subpart Ja.

The East Flare is equipped with an $H_2S$ CEMS to demonstrate compliance with the Subpart Ja $H_2S$ limits. It is also equipped with a total sulfur monitor that is used to determine compliance with the WAC 173-400-040(6), NWCAA 462 (1,000 ppmvd at 7% $O_2$), and OAC 918b Condition 1. The CEMS are located on the primary East Flare downstream of the split to the North and South flares. As such, PSR requested and EPA granted an Alternative Monitoring Plan (AMP) on March 22, 2011, which has been revised on August 21, 2012 and January 10, 2014, to allow the $H_2S$ CEMS data from the East Flare to be representative of each flare operating at that time for determining compliance with 40 CFR 60 Subpart Ja. In addition, when the East Flare, and hence the CEMS, is out of service, PSR shall use engineering judgment and existing data to determine $H_2S$ emissions from the North and/or South Flares.

**Flare Gas Recovery (FGR):** The FGR project was permitted under OAC 918 issued June 9, 2005. The FGR project began operation on June 27, 2006, prior to the December 31, 2006 Consent Decree deadline. The FGR project is subject to NSPS Subpart GGG and MACT Subpart CC for equipment leaks and NSPS Subpart QQQ and MACT Subpart CC for process drains. OAC 918 has since been revised to OAC 918a (issued April 8, 2010) to allow excess clean hydrogen to bypass the FGR along with non-construction-related regulatory applicability, compliance demonstration, and verbiage changes. OAC 918b was issued on January 30, 2014 to clarify the leak detection and repair requirements.

As gases recovered by the FGR system are burned in fuel gas combustion devices throughout the refinery, NSPS Subpart J allows the refinery to monitor hydrogen sulfide ($H_2S$) in the fuel gas instead of monitoring stack sulfur dioxide ($SO_2$) emissions. PSR generally complies by monitoring fuel gas $H_2S$ concentration at the main fuel gas mix drum which feeds most of the combustion units in the refinery.

NSPS Subpart J requires that the concentration of $H_2S$ in refinery fuel gas not exceed 230 mg/dscf (dry standard cubic feet), based on a 3-hour average, with standard conditions defined in 40 CFR 60 Subpart A as 293 Kelvin and 101.3 kilopascals. Because $H_2S$ is continuously monitored as ppmvd, the NSPS Subpart J standard of 230 mg/dscm has been converted to ppm and the ppm limit included in applicable AOP term.

$$\frac{230\ mg\ H_2S}{dscm\ air} \times \frac{1\ g\ H_2S}{1{,}000\ mg\ H_2S} \times \frac{1\ mol\ H_2S}{34.082\ g\ H_2S} \times \frac{24.056\ L\ H_2S}{mol\ H_2S\ (ideal\ gas\ law)} \times \frac{1\ dscm\ H_2S}{1{,}000\ L\ H_2S}$$

$$= \frac{162\ dscm\ H_2S}{1{,}000{,}000\ dscm\ air} = 162\ ppmvd\ H_2S\ in\ air$$

The exceptions to the monitoring scheme generally used to monitor fuel gas $H_2S$ at PSR are the heaters associated with the HTU1/CRU1, HTU2, and HTU3 units. These heaters are primarily fired with fuel gas generated within each respective process unit. As such, monitoring $H_2S$ concentration at the main fuel gas drum for these heaters is not representative and the $H_2S$ concentration for the fuel gas for the heaters associated with these units must be monitored independently.

For HTU1/CRU1 (i.e., 7C-F4/F5), the refinery elects to monitor $SO_2$ as it comes out of the heater stack. Because heaters 6D-F2, 6D-F3, and 6D-F4 utilize the same fuel gas, these three heaters rely on the 7C-F4/F5 CEMS for compliance. For HTU2 (i.e., 11H-101, 11H-102, and 11H-103) and HTU3 (i.e., 60F-201), the refinery elects to monitor $H_2S$ concentration in the fuel gas at the respective fuel gas drum on each unit.

## 3.12 <u>Internal Combustion Engines</u>

### 3.12.1 Control Room #2 Generator (30LEG2), BOHO Firewater Pump (33PGE3), BOHO Firewater Pump (33PGE14), & BOHO Firewater Pump (33PGE15)

The Control Room #2 Generator (30LEG2) provides support during power outages for the #2 Control Room. The three BOHO Firewater Pumps are used to pressurize the refinery firewater system which services the entire refinery. The refinery firewater system provides pressurized water to fight fires but the system is also used for general maintenance, such as washing pads down, and fire training.

As can be seen in SofB Table 2-5, these four compression-ignition engines are in emergency service, were installed prior to June 12, 2006, and are rated at less than 500 hp; as such, these four units are subject to the same requirements under 40 CFR 63 Subpart ZZZZ and are grouped together in the AOP. They are not subject to any NSPS requirements.

Note that this regulatory analysis assumes that the engines are in emergency service as defined in 40 CFR 63 Subpart ZZZZ and discussed in SofB Section 2.24. This definition allows for limited operation in non-emergency service. Should PSR choose to operate them otherwise, these engines would be subject to other requirements.

Also, it is assumed that the engines are not used for emergency demand response or voltage/frequency deviations. Should PSR choose to use the engines for either of these purposes, additional requirements will become applicable.

Most MACT standards require an initial notification under 40 CFR 63.9. However, because these RICE are existing emergency units, these RICE are exempt from the initial notification requirement pursuant to 63.6645(a)(5).

### 3.12.2 Stand-by Wharf Generator (30LEG5)

On February 27, 2002 the NWCAA issued OAC 797 for the construction of a 500 kW (755 hp) emergency stand-by electrical generator to serve as backup power in the event of an electrical power disruption. This effort to assure reliability for marine terminal operations will reduce the potential for oil spills. The generator was installed and started operation on November 26, 2002. The OAC limits the number of operating hours which enabled the unit to meet the air toxics in accordance with ch 173-460 WAC. The OAC also limits opacity to 5% and fuel to ultra-low sulfur diesel.

There are no applicable NSPS requirements to this engine, but 40 CFR 63 Subpart ZZZZ, the NESHAP for reciprocal internal combustion engines (RICE), applies. As an existing emergency stationary RICE with a site rating greater than 500 hp at a major source of HAP emissions, pursuant to 40 CFR 63.6590(b)(3), this engine is not required to comply with 40 CFR 63 Subpart ZZZZ or the General Provisions under 40 CFR 63 Subpart A, including the initial notification requirements. The engine is subject to 40 CFR 63 Subpart ZZZZ but has no requirements; therefore, 40 CFR 63 Subpart ZZZZ is not listed in AOP Section 5.

Note that this regulatory analysis assumes that the engine is in emergency service as defined in 40 CFR 63 Subpart ZZZZ and discussed in SofB Section 2.24. Should PSR choose to operate it otherwise, this engine would be subject to other requirements.

Also, it is assumed that the engine is not used for emergency demand response or voltage/frequency deviations. Should PSR choose to use the engines for either of these purposes, additional requirements may become applicable.

OAC 797 Condition 1 lists the opacity standard for the generator. Because this generator is a late model engine, designed to provide efficient operation such that visible emissions are not expected. As such, the compliance demonstration is maintenance in accordance with the manufacturer's specifications.

**Excluded Conditions:** OAC 797 Condition 4 stating that the NWCAA shall be notified in writing of the generator installation date within 30 days of completion is not listed in the AOP because it is a one-time condition that has been completed.

### 3.12.1 Main Control Room Emergency Generator (30LEG6) & Radio Tower Emergency Generator (30LEG7)

The Main Control Room Emergency Generator was installed in 2008. Because of this installation date, it is assumed to be a model year 2007 or more recent. It is rated at 237 hp and has a cylinder displacement of 6.8 liters/cylinder. As a diesel emergency generator that operates for less than 500 hours per year, it is exempt from New Source Review requirements under NWCAA 300.4(i).

The Radio Tower Emergency Generator was installed in 2013. It is a 2013-model-year 2.6-liter engine rated at 50 kW. As a diesel emergency generator that operates for less than 500 hours per year, it is exempt from New Source Review requirements under NWCAA 300.4(i).

The Main Control Room Emergency Generator and the Radio Tower Emergency Generator are considered "new" units under 40 CFR 63 Subpart ZZZZ since they were constructed after June 12, 2006. As stationary compression ignition internal combustion engines that were manufactured after April 1, 2006 and commenced construction after July 11, 2005, these RICE are also subject to 40 CFR 60 Subpart IIII. 40 CFR 63 Subpart ZZZZ provides the following overlap provisions for engines that are also subject to 40 CFR 60 Subpart IIII.

For new CI engines equal to or less than 500 hp:

> *63.6590(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*

As such, the Main Control Room Emergency Generator and the Radio Tower Emergency Generator are subject to 40 CFR 63 Subpart ZZZZ but demonstrate compliance through compliance with 40 CFR 60 Subpart IIII.

The engines are certified Tier 3 so they satisfy the requirement in 40 CFR 60 Subpart IIII (40 CFR 60.4211(c)). It is assumed that the engines are installed, configured, operated, and maintained according to the manufacturer's emission-related instructions and the emission-related settings are only changed in a way permitted by the manufacturer. Should this change, a compliance demonstration will be required (40 CFR 60.4211(g)).

Note that this regulatory analysis assumes that these engines are in emergency service as defined in 40 CFR 63 Subpart ZZZZ and discussed in SofB Section 2.24. Should PSR choose to operate them otherwise, these engines would be subject to other requirements.

Also, it is assumed that the engines are not used for emergency demand response or voltage/frequency deviations. Should PSR choose to use these engines for either of these purposes, different requirements will become applicable.

Pursuant to 40 CFR 60.4214(b), as emergency stationary ICE, an initial notification is not required for the Main Control Room Emergency Generator and the Radio Tower Emergency Generator.

### 3.12.2 EP Outfall Pump (9QG68)

The Effluent Plant Outfall Pump is used to discharge treated water from the final retention pond to Fidalgo Bay. It is used during power outages to prevent the pond from overflowing; however, because it is the largest pump available, it is also used when the capacities of the other pumps are exceeded or not available and the pond level must be reduced. Additionally, it is used to provide firewater to the Dock.

The EP Outfall Pump engine was installed in 2014. It is a 2013-model-year rated at 373 kW (500 hp) with a cylinder displacement of 2.5 L/cyl (total displacement of 15 L with 6 cylinders). Because the diesel compression ignition (CI) engine was installed after June 6, 2006, it is considered a new engine under 40 CFR 63 Subpart ZZZZ. Because it will operate more than 100 hours per year, it is considered in non-emergency service under 40 CFR 63 Subpart ZZZZ. However, as a diesel pump engine that operates for less than 500 hours per year in emergency service, it is exempt from New Source Review requirements under NWCAA 300.4(i).

As a stationary compression-ignition internal combustion engine that was manufactured after April 1, 2006 and commenced construction after July 11, 2005, this RICE is also subject to 40 CFR 60 Subpart IIII. Similar to the Main Control Room and the Radio Tower Emergency Generators, the overlap provisions in 40 CFR 63 Subpart ZZZZ state that the EP Outfall Pump engine is subject to 40 CFR 63 Subpart ZZZZ but demonstrates compliance through compliance with 40 CFR 60 Subpart IIII.

Subpart IIII has different standards for general internal combustion engines and fire water pumps. The EP Outfall Pump Engine does provide fire water to the Dock but it is not certified by the NFPA. As such, it is subject to the general ICE standards.

Subpart IIII requires that 2007 model year and later non-emergency stationary CI ICE rated at less than 3,000 hp with a displacement of less than 10 L/cyl meet the new nonroad engine standards for the same model year and maximum engine power listed in 40 CFR 89 and 40 CFR 1039. These new nonroad engine regulations require automatic increases in stringency over time – in January 2011, new nonroad engines are required to meet reduced PM and $NO_X$

emissions over what was required for Tier 3 engines. Beginning in January 2014, an additional $NO_X$ reduction is required beyond the reduction required in 2011.

As a 2013 model year, the EP Outfall Pump engine falls in this interim period (a so-called Interim Tier 4 engine). The Cummins QSX15 engine is designed to meet the Interim Tier 4 standards under 40 CFR 1039.102(b) Table 6 using cooled exhaust gas recirculation (EGR) for $NO_X$ and a particulate filter for PM. However, Cummins utilizes the alternative $NO_X$ standard under 1039.102(e) for during the phase-in of the Tier 4 standards. As such, the engine meets the emission limits beginning January 2011 without the additional $NO_X$ reduction required in 2014: $NO_X$: 2.0 g/kW-hr, NMHC: 0.19 g/kW-hr, CO: 3.5 g/kW-hr, PM: 0.02 g/kW-hr.

The particulate filter is required to be monitored using a back-pressure sensor that will alert when the back-pressure reaches the engine limit.

Note that the smoke standard in 40 CFR 1039.105 does not apply because certified to a PM standard below 0.07 g/kW-hr (i.e., 0.02 g/kW-hr). Also, the evaporative standards in 40 CFR 1039.107 does not apply to diesel engines.

Tier 4 Interim requires that crankcase emissions, also known as blowby gases, be included in the overall regulated engine emissions. To control blowby gas emissions, the engine utilizes a "dripless" crankcase breather system with a coalescing filter element. The filter returns the oil to the crankcase and provides the added benefit of removing oil mist and tiny oil droplets, resulting in a cleaner engine and powertrain.

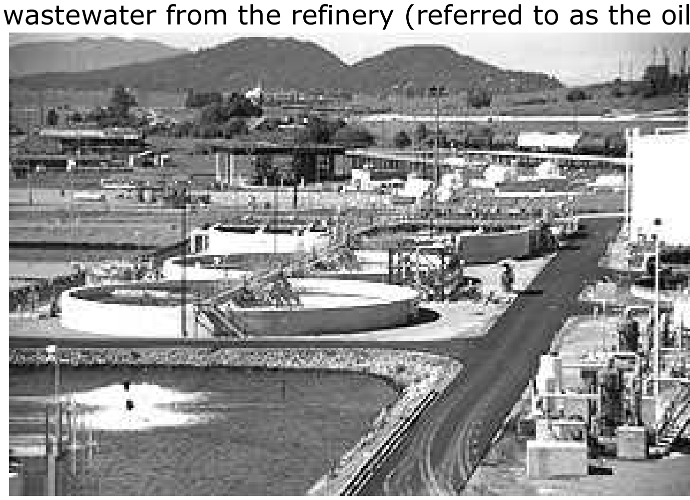
Subpart IIII also requires that the engine use ultra low sulfur diesel (15 ppm). Cummins requires the use of ULSD in order to meet the PM standard.

It is assumed that the engine is installed, configured, operated, and maintained according to the manufacturer's emission-related instructions and the emission-related settings are only changed in a way permitted by the manufacturer. Should this change, the compliance demonstration under 40 CFR 60.4211(g) will be required.

Pursuant to 40 CFR 60.4214(a), an initial notification is only required for non-emergency stationary ICE that are greater than 3,000 hp, have a displacement of greater than or equal to 10 L/cyl, or are pre-2007 model year engines that are greater than 175 hp and not certified. Because the EP Outfall Pump does not meet any of these criteria, an initial notification is not required.

## 3.13 <u>Wastewater and Effluent Plant</u>

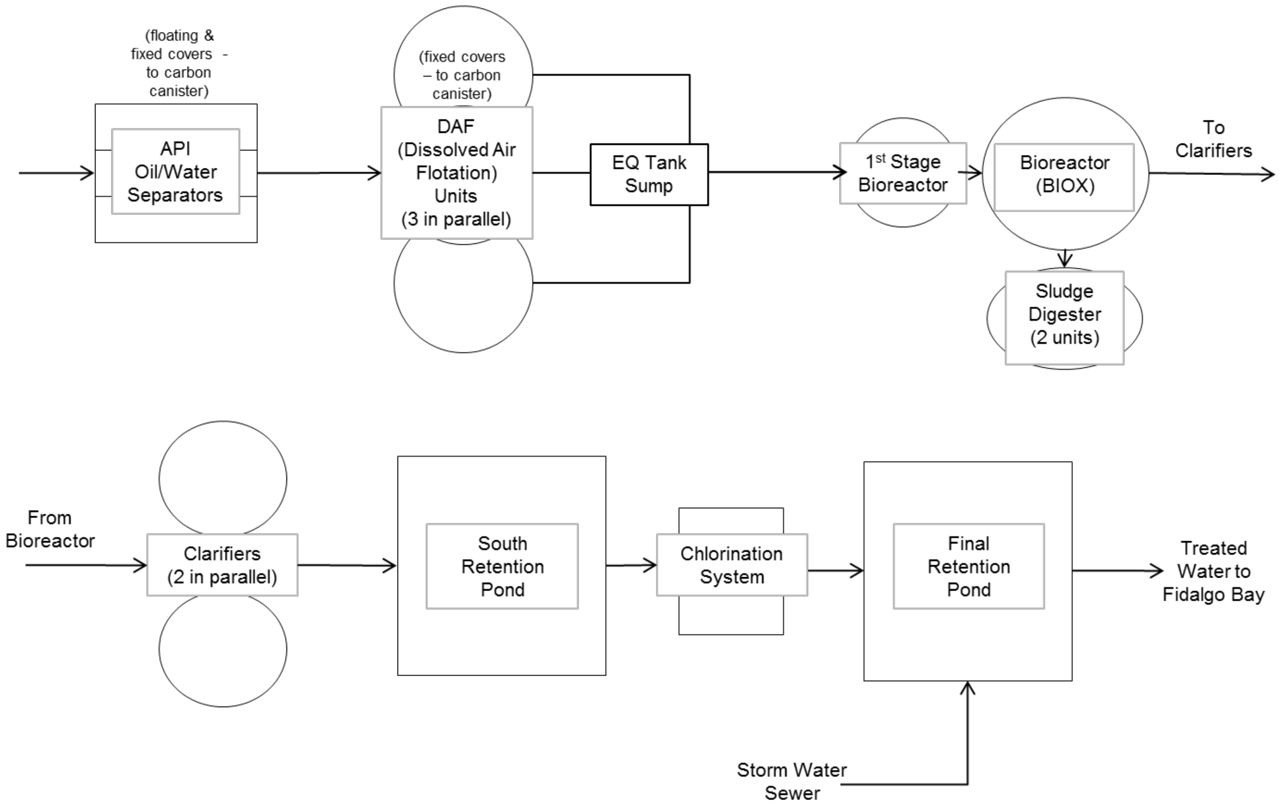
The Effluent Plant treats oil-contaminated wastewater from the refinery (referred to as the oily water sewer) that is routed through the process water sewer system. Sources of oily water include catch basins located under processing units, storage tank drains, and ballast water from ships and barges. Oil that is recovered at the Effluent Plant is sent back to the VPS for processing. Left-over solids are dewatered for shipment off-site.



Clean runoff water is treated through a separate storm water sewer system and is discharged with minimal treatment. All treated wastewater is discharged into Fidalgo Bay and tested for water quality in accordance with PSR's National Pollution Discharge Elimination System (NPDES) permit issued by the Washington Department of Ecology.

Oily wastewater from refinery processes are generally routed through drains controlled by p-trap-type water seals routinely inspected as part of the refinery's wastewater program. These drains largely flow into the main controlled sewer system as they approach the Effluent Plant. Note that PSR has chosen to control the oily wastewater drain systems associated with the tank farm. In areas where the sewer system must "breathe", closed vents are installed and routed to carbon canisters which capture the hydrocarbon emissions. At junction boxes, water seals are used to prevent the sewer system from venting directly to atmosphere.

When the oily process water arrives at the Effluent Plant, it is routed into a gravity-based API oil/water separator. Here flow rates are reduced allowing oils to float to the surface which are skimmed off. Following the API, further physical oil-water separation occurs at the Dissolved Air Flotation units (DAFs). The DAF units inject nitrogen into the oil/water solution, oil accumulates on the rising bubbles and skimming takes place at the surface to complete the separation process. After the API and DAFs, the remaining contaminants are removed through biological treatment. Treated wastewater is disinfected in a chlorination step prior to discharge into Fidalgo Bay. A flow diagram of the Effluent Plant is shown in Figure 7.




## Figure 9 PSR Effluent Plant Flow Diagram

Because of the potential for VOC/HAP emissions, portions of the Effluent Plant are covered and sealed. The API forebays are covered with a fixed roof routed to activated carbon; the API main bays are covered with a floating roof. As with the API forebays, the DAF units are also covered with fixed roofs with any vapor emissions routed through activated carbon. The wastewater stream then enters the uncontrolled First Stage Bioreactor (formerly Tank 74); it serves as a pre-reactor for the bioreactor and any odors are controlled as needed using a biofilm filter system.

The refinery does not operate any active benzene treatment processes (e.g., steam stripping unit, thin-film evaporation unit, waste incinerator, furnace or boiler burning hazardous waste for energy recovery) beyond the wastewater treatment plant. In addition, the only control devices the wastewater treatment plant uses is carbon canisters; the carbon is shipped off-site for regeneration.

Because the sanitary sewer is also treated by the Effluent Plant, the treated water is chlorinated prior to release into Fidalgo Bay. Chlorine gas was originally used as the chlorination agent; in 1996/97, PSR switched to bleach (sodium hypochlorite). Sludge from the wastewater treatment process is shipped offsite as regulated waste.

### Construction History and Regulatory Discussion

The original refinery was constructed with an oily water sewer system and effluent plant in 1958. The entire oily water sewer system and effluent plant were vented to the atmosphere until 1990 at which time NWCAA 580.23 required that the API forebays be covered. Shortly thereafter, 40 CFR 61 Subpart FF was promulgated requiring the refinery to control emissions from applicable wastewater systems having benzene concentrations greater than 10 ppm. As a result, covers were installed on the API mainbays (OAC 332 issued September 30, 1991) and afterbays (OAC 416 issued January 12, 1993 for DAFs 1&2), the trickling filter was removed and a new biological treatment system was installed. In order to bring benzene concentrations down to acceptable levels prior to open-air biological treatment, an additional DAF unit was installed after the API (OAC 514 issued July 11, 1994 for DAF 3). In addition, the main oily water sewer line running from the tank farm to the Effluent Plant was sealed and, where "breathing" was necessary, carbon canisters were installed on the vent lines (OAC 417 issued January 6, 1993). Because these projects and OACs were related and relatively close in time, these four OACs were combined into OAC 514a issued April 10, 2013.

The EP went through an upgrade in 1996. Two clarifiers were built, one of the two original retention ponds was removed (the south pond remains), and the original aerator/clarifiers were converted into sludge digesters. No construction permit was issued for this upgrade.

Benzene-contaminated wastewater that was being stored (or treated) in tanks was also controlled by installing either IFR tanks or by having fixed roof tanks that vent through a closed vent system to activated carbon (OAC 241 issued January 14, 1988 for construction of IFR Tank 70, RO issued January 26, 1990 to convert fixed roof Tank 62 to an IFR by May 31, 1990, OAC 316 issued May 18, 1990 for construction of IFR Tank 71, OAC 341 issued September 12, 1991 to convert fixed roof Tank 60 to an IFR, and OAC 345 issued November 1, 1991 to construct EFR Tanks 72 and 73 and fixed roof Tank 74 with activated carbon). Each of these OACs have been updated in preparation for inclusion in the AOP.

To resolve an enforcement action, PSR installed an odor neutralizer system on the Effluent Plant bioreactor for which the NWCAA issued Regulatory Order (RO) 33 on July 15, 2008. Based on the Agency complaint load, the odor neutralizer system did not seem to be effective in this application; as such, upon request, the NWCAA rescinded RO 33 on June 12, 2013.

In July 2013, Tank 74 began operation after having been converted from a controlled surge tank to the First Stage Bioreactor. During the conversion, the tank was outfitted with air distribution units and stocked with the same activated sludge as in the existing bioreactor. After the conversion, the First Stage Bioreactor (Tank 74) is no longer a controlled unit under 40 CFR 61 Subpart FF being equipped with activated carbon; any odors from the vessel are controlled using a biofilm filter system.

**Effluent Plant and Sewer System (ETPPDF)**: Wastewater regulatory applicability is discussed in great detail under SofB Section 2.1.2. Regulatory discussion, outside applicability, follows.

According to §61.357(d)(1), the annual TAB report is due 90 days after January 7$^{th}$. However, once the requirement is rolled into the AOP, reports must be submitted on the AOP schedule based on WAC 173-401-615(3). As such, the annual TAB report is due within 30 days of the end of the applicable period (i.e., January 30$^{th}$ for annual reports).

PSR complies with the BQ6 alternative under 40 CFR 61.342(e). This option means that the uncontrolled streams at the refinery must not exceed 6 Mg of benzene during the calendar year as demonstrated in the annual TAB/BQ6 analysis. Note that the uncontrolled streams in the BQ6 analysis must include remediation wastes, wastes generated during process turnarounds, wastes shipped offsite, and all dilute streams except the stream that has less than 10 ppmw coming out of the wastewater treatment plant.

**Effluent Plant Storage Tanks**: Wastewater tank regulatory applicability is discussed under SofB Section 2.1.2. Regulatory discussion and construction history, outside applicability, follows. Table 3-2 lists wastewater tank permit number and associated construction/modification date.

Tanks 60 and 62 were constructed with the original refinery in 1958 but were fitted with internal floating roofs in the early 1990s. Pursuant to 40 CFR 60.14(e)(5), addition of control devices (such as floating roofs) are not considered modifications under NSPS; therefore, these tanks remain not subject to 40 CFR 60 Subpart Kb.

However, Tanks 70, 71, 72, and 73 were constructed after the Subpart Kb applicability date and are therefore potentially subject. Because of the variability in the contents and vapor pressures in the Effluent Plant storage tanks, it is conservatively assumed that Subpart Kb applies to each.

According to a letter from PSR dated October 13, 2004, PSR conducted a review pursuant to the Equilon Consent Decree and determined that Tanks 60, 61, 62, 70, 71, 72, and 73 are subject to 40 CFR 60 Subpart Kb.

### Table 3-2: OACs for Wastewater Tank Construction/Modification

| Tank ID# | OAC# | Product Stored | Construction/Modification Date |
|---|---|---|---|
| 60 | 341a | Wastewater, ballast water | 1958 Modified 1991 |
| 70 | 241a | Wastewater, emulsion breaker | 1988 |
| 71 | 316a | Wastewater, API skim | 1990 |
| 72 | 345a | Wastewater, post-API surge | 1991 |
| 73 | 345a | Wastewater, post-API surge | 1991 |

**Excluded Conditions**: There are a number of wastewater-related orders issued by the NWCAA with applicable requirements beyond those required in federal, state and local regulations. Some conditions of those orders have not been incorporated into the AOP for the following reasons.

OAC 514a (issued April 10, 2013) Conditions 1, 2, 3, and 4 requiring notification when construction or installation is complete and operation is expected to begin are not listed in the AOP because they are each one-time requirements that have been completed. As such, OAC 514a is not listed in AOP Section 5.

Condition 1 of OAC 316a (issued April 10, 2013) for Tank 71 requiring notification prior to placing the tank into service is not listed in the AOP because it is a one-time requirement that has been completed. As such, OAC 316a is not listed in AOP Section 5.

Condition 1 of OAC 345a (issued April 10, 2013) for Tanks 72, 73, and 74 requiring notification when the project was complete is not listed in the AOP because it is a one-time requirement that has been completed. As such, OAC 345a is not listed in AOP Section 5. Additionally, this OAC is not listed in AOP Section 1 for the First Stage Bioreactor (formerly Tank 74) because Tank 74 is no longer considered a storage tank but part of the bioreactor system.

The Regulatory Order issued January 26, 1990 regarding conversion of fixed roof Tank 62 to an internal floating roof tank by May 31, 1990 is not listed in the AOP because the requirement has been completed as evidenced by the NWCAA inspection report on April 3, 1990.

## 3.14 Storage Tanks/Vessels

The refinery maintains several storage tanks (also referred to as storage vessels) to provide storage for raw materials, intermediates, and final products. Tank emissions result from evaporation of stored volatile organic compounds ("breathing" losses) and from vapors displaced as tanks are filled ("working" losses). The tank designs and counts (not including wastewater tanks at the effluent plant) at PSR are as follows:

(32) external floating roof (EFR) tanks

(15) internal floating roof (IFR) tanks

(18) fixed roof tanks

(15) pressurized storage vessels

Tank designs subject to air pollution control requirements are EFR, IFR, and fixed roof tanks. Note that storage tanks located at the Effluent Plant are addressed under SofB Section 3.13.

The majority of high vapor pressure (>1.5 psia) volatile organic liquids (VOLs) at PSR are stored in EFR tanks. All EFR tanks use a double seal system between the tank wall and floating roof cover as required by underlying regulations. Generally, the double seal configuration at PSR is a metallic shoe primary seal and a rim-mounted secondary seal.

IFR tanks are also used to store high vapor pressure VOLs at the refinery, as well as a wide array of materials (e.g., slop oils, wastewater emulsions). At PSR, IFR tanks generally use a fixed cone roof covering the top of the tank along with an internal floating roof having at least a one seal system between the tank wall and floating roof. In some cases, two internal seals are used for added emission control. IFR tanks equipped with a double seal system are allowed a more flexible inspection schedule under NSPS and Refinery MACT 1 regulations.

For both external floating and internal floating roof tanks, visual internal inspections of the roof deck, deck fittings, and rim seals from within the tank are required at least every 10 years, or every time the tank is emptied and degassed, whichever occurs first. The inspection must check for stored liquid on the floating roof, holes or tears in either primary or secondary seals, functionality of floating roof deck, deck fittings, and rim seals, and that any openings through the floating roof are covered or closed with a gasket, seal or wiper with no gaps greater than 1/8$^{th}$ inch. If there is visual access to the floating roof deck, all deck components and rim-seals, this inspection may be performed entirely from the top side of the floating roof - meaning from on top of the floating roof, and in the case of an IFR, under the fixed roof and internal to the tank. If all components cannot be visually inspected while the tank remains in-service, the tank must be emptied to perform this required internal visual inspection.

For an IFR tank, annual visual inspections may be conducted through roof hatches or manholes on top of the tank as long as all components are visible. Inspections are conducted to observe the floating roof deck, deck fittings, & upper rim seal for the presence of stored liquid on the floating roof, holes or tears in the upper rim seal, or an indication that the deck, deck fittings or rim seals are not functioning as designed. If the IFR tank has double seals, the floating roof visual internal inspection can be performed every 5 years, in lieu of performing both annual roof hatch inspections and 10-year floating roof visual internal inspections.

For EFR tanks, gaps between the floating roof seal and tank wall must be measured: every year for each secondary seal and every 5 years for each primary seal. EFR tanks that are also subject to NWCAA 580.9 are also required to inspect the integrity of gasketing and other visible seal systems semiannually.

EFR and IFR tanks may not store volatile organic products that exceed a maximum true vapor pressure of (MTVP) of 11.1 psia. Because vapor pressure characteristics of crude oils and other non-finished products can vary considerably, their vapor pressures are sampled and tested to assure they remain below 11.1 psia. In addition, some tanks have internal heaters that can increase storage temperatures above ambient to manage material viscosity. Temperature and vapor pressure are recorded and MTVP are calculated using methods in API Chapter 19.2 *Evaporative Loss from Floating Roof Tanks* (previously API Bulletin 2517).

NWCAA is notified in advance of internal tank inspections and gap measurements on floating roof tanks. The notices provide NWCAA the opportunity to observe the inspections and gap measurements. Any seal gap or other defects found during inspection that exceed the compliance thresholds are required to be corrected within 45 days unless a 30-day extension is used by the refinery. The refinery can utilize up to (2) 30-day repair extensions when alternative storage capacity is unavailable.

The fixed roof tanks at PSR are generally equipped with cone roofs. In general, fixed roof tanks are exempt from air pollution control requirements, beyond keeping records of tank dimensions and information on the products that they store. Fixed roof tanks are limited by rule to storing materials with vapor pressures of 0.75 psia or less.

Gaseous products, such as butane, propane and LPG are stored in pressurized vessels. There are no requirements for pressurized vessels as they are considered closed systems that do not vent to the atmosphere. However, each is equipped with a pressure relief device (PRD) that reduces stress on the vessel before the tank itself is damaged. Storage tank PRDs are routed through a closed vent system to the flares.

## Construction History and Regulatory Discussion

Several of the refinery storage tanks were built as part of the original refinery construction in 1958. A few tanks were added in the early 1970s, and a few more have been added or modified since. Several fixed roof storage tanks were constructed with the original refinery in 1958 but were later fitted with floating roofs (i.e., Tanks 14, 15, 30, TK-15D-100A, TK-15D-100B, and TK-15D-100C); addition of the control devices does not trigger a modification in accordance with 60.14(e)(5), therefore these tanks remain not subject to NSPS K, Ka or Kb.

According to a letter from PSR dated October 13, 2004, PSR conducted a review pursuant to the Equilon Consent Decree and determined that Tanks 12, 13, and 14 are subject to 40 CFR 60 Subpart Kb. See the tables in AOP Section 1.14 for specific tank service and construction dates.

Table 3-3 lists tanks that have received construction/modification permits and their applicable construction dates.

## Table 3-3: OACs for Tank Construction/Modification

| Tank ID# | OAC# | Product Stored | Construction/Modification Date |
|---|---|---|---|
| 15 | 262a | Coker Heavy Gas Oil | 1958 Modified 1990 |
| 38 | 295a<br>CO 08 | Gasoline | 1991 |
| 39 | 337a | Gasoline | 1992 |
| 45 | 297a | HS Diesel | 1991 |
| 80 | 296a | Nonene | 1990 |
| 81 | 296a | Nonene | 1990 |
| 82 | 296a | Nonene | 1990 |
| 85 | 1046 | Ethanol | 2010 |
| 503 | 1291 | Crude | 2020 |
| 504 | 1301 | Diesel | TBD |
| 505 | 1301 | Gasoline | TBD |

The applicability of federal and local regulations to various storage vessels within the refinery are discussed in detail in SofB Section 2.1.2. Regulatory discussion, outside applicability, follows.

NWCAA 580.32 allowed three options when defining a control strategy for controlled tanks:

- 580.32 It shall be unlawful for any person to cause or allow storage of volatile organic compounds as specified in Section 580.31 unless each storage tank or container:
  - 580.321 Meets the equipment specifications and maintenance requirements of the Federal Standards of Performance for New Stationary Sources -Storage Vessels for Petroleum Liquids (40 CFR 60, subpart Kb); or
  - 580.322 Is retrofitted with a floating roof or internal floating cover using a metallic seal or a nonmetallic resilient seal at least meeting the equipment specifications of the Federal standards referred to in 580.321 of this subsection, or its equivalent; or
  - 580.323 Is fitted with a floating roof or internal floating cover meeting the manufacturer's equipment specifications in effect when it was installed.

EFR and IFR tanks at PSR subject to control requirements in NWCAA 580.32 were fitted with a floating roof or internal floating cover meeting the manufacturer's equipment specifications in effect when installed to meet this requirement. Many of the NWCAA tank control and operational requirements do not include adequate monitoring to reasonably assure continuous compliance. As such, NWCAA used its gap-filling authority under WAC 173-401-615 to require monitoring provisions from associated federal tank standards that also applicable to the individual tank(s) to satisfy monitoring for the applicable NWCAA requirements. Where this has been done in the permit for tank requirements, the MR&R column lists "*DIRECTLY ENFORCEABLE*" and under this heading, refers to the MR&R under the specific AOP term for the associated federal standard for the individual tank(s).

PSR submitted Notification of Compliance Status to NWCAA May 30, 2018 noting that there were no changes to the status of their Group 1 storage vessels, and that all Group 1 storage vessels were in compliance with Refinery MACT 1 §63.660, and under the overlap provisions, met the tank fitting control requirements under 40 CFR 63 Subpart WW Tanks Control Level 2.

Per 63.646, once PSR demonstrated compliance with the standards in §63.660, the standards in §63.646 no longer applied. For Group 1 storage vessels, the conditions in the AOP that previously referenced §63.646 and required compliance with 40 CFR 63 Subpart G (Conditions in section 5.14) have been updated to reference §63.660 and require compliance with 40 CFR 63 Subpart WW Tanks Control Level 2.

PSR has not chosen to request any alternative means for determining compliance for any storage vessel and therefore none are listed in the AOP.

PSR entered into a Storage Tank Emission Reduction Partnership Agreement with EPA. This agreement required PSR to install and maintain a cover on the slotted guidepole opening on Tank 38. Pursuant to paragraph 31, the requirement to install, maintain, and inspect the slotted guidepole cover survives the termination of the agreement. The NWCAA issued Compliance Order (CO) 08 to memorialize this requirement and create an applicable requirement for inclusion in the AOP.

**Excluded Conditions:** There are a number of tanks that have orders issued by the NWCAA with applicable requirements beyond the applicable federal, state, and local requirements. Some conditions listed in the orders are not listed in the AOP for the following reasons.

Condition 1 of OAC 262a (issued April 10, 2013) for Tank 15 requiring notification when construction of the floating roof is complete is not listed in the AOP because it is a one-time requirement that has been completed. As such, OAC 262a is not listed in AOP Section 5.

Note that Tank 20 is an EFR tank used to hold sour water at the refinery. Although this tank is not subject to specific regulation, controls are in place to limit its potential for odorous emissions.

Condition 1 of OAC 295a (issued April 10, 2013) for Tank 38 requiring notification prior to placing the tank into service is not included in the AOP because it is a one-time requirement that has been completed.

Condition 2 of OAC 1291 (issued June, 7, 2018) for construction of crude storage tank Tk 503 requiring notification of initial tank filling is not included in the AOP because it is a one-time requirement that was completed September 25, 2020.

## 3.15 Refinery Support Operations

### 3.15.1 Refinery Laboratory

PSR performs various chemical analysis activities associated with their refinery processes, requiring an on-site laboratory. In 2017, PSR built a new laboratory to replace their existing lab, approved in OAC 1215 (issued July 30, 2015). The project triggered new source review under NWCAA regulations due to applicability of 40 CFR 60 Subpart QQQ and 40 CFR 61 Subpart FF, due to installation of a new individual drain system needed to collect oily wastewater runoff from the laboratory and connect into the refinery’s existing wastewater system.

**Excluded Conditions**: Condition 2 of OAC 1215 required decommissioning of the existing laboratory once the new laboratory had been constructed. Condition 3 of OAC 1215 required notification of startup of the new laboratory within 15 days of beginning operation. NWCAA received notification that the old lab had been decommission June 12, 2017 and the new lab began operating February 5, 2017. Conditions 2 & 3 are one-time requirements that have already been completed and therefore were not included in the AOP.

### 3.15.2 Spray Coating Operations

PSR paints piping, structural components, vessels and fabricated assemblies inside an existing (used on site for more than 20 years) enclosed spray area, located at the Tank Farm, within a 3-

sided Quonset building. A dust collector is used for filtration, as needed. Coatings are applied in the Quonset building via airless and hvlp spray systems, brush and roller.

NWCAA Section 508.4(A)(1)(c) applies to this existing enclosed spray area located outdoors. It requires a complete 3-walled and roofed enclosure. Because PSR has operated this spray coating operation without a negative pressure ventilation (NPV) system since before April 20, 2018, a NPV system is not required to be installed, as long as spray coating does not create a nuisance. All spray coating must be performed using one of the required spray application methods (i.e., HVLP, airless or air-assisted airless, electrostatic, or a method with transfer efficiency of at least 65%). No visible emissions from spray coating operations are allowed, spray guns and equipment must be cleaned without atomizing the solvent into the air during cleanup and all VOC-containing materials must be kept in closed container except when materials are actively being added or removed. Records of environmental data sheets that clearly indicate the contents of the spray coatings and solvents used, total coating and solvent purchases, and disposal of waste material must be kept for 3 years from the date of generation.

**Excluded Conditions**: NWCAA 508.4(A)(2) Filtration and NWCAA 508.4(A)(4) Vertical Unobstructed Exhaust Vent and associated recordkeeping under NWCAA 508.4(A)(8)(c), (d), and (e), are not included in the AOP because PSR's spray enclosure is not required to meet the filtration and exhaust vent requirements per NWCAA 508.4(A)(1)(c).

### 3.15.3 Gasoline Dispensing

Vapor control requirements in NWCAA 580.6(B) apply to all gasoline dispensing facilities with an annual 12-consecutive month throughput equal to or greater than 120,000 gallons. PSR operates one 2,000 gallon aboveground gasoline tank to fuel refinery fleet vehicles, and annual throughputs are less than half the threshold to require vapor control.

To be exempt from the remaining requirements in NWCAA 580.6, the gasoline tank must have:

- a capacity less than 2,000 gallons if installed before January 1, 1990;
- offset fill lines installed before January 1, 1990; or
- a capacity less than 264 gallons.

As PSR's tank is not exempt, the gasoline storage tank must be equipped with properly functioning pressure vacuum vent (PV) caps and maintained in a vapor-tight condition and in good working order, including but not limited to all caps, adaptors and drain valves.

**Excluded Conditions:** As discussed above, NWCAA 580.6(B) is not included in the AOP because PSR does not have gasoline throughput that triggers these requirements. NWCAA 580.6(F) is not included in the AOP because PSR does not have Stage I vapor recovery.

# 4. AIR OPERATING PERMIT ADMINISTRATION

In developing the AOP for PSR, the NWCAA developed assumptions for the AOP and established permit elements. Assumptions are discussed in Section 4.1. Permit elements are presented in Section 4.2. Section 4.3 lists the AOP Public docket information. Finally, Section 4.4 lists the definitions and acronyms used throughout the SofB and AOP.

## 4.1 Permit Assumptions

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

### 4.1.1 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.

### 4.1.2 "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 considered to be "narrative only". These permits are all relatively old, all originally being issued prior to 1986. Because they are narrative in content, they do not contain any specific conditions that are considered specifically applicable requirements under Title V.

- OAC 74 (July 19, 1972): Octane Improvement Project
- Letter issued May 24, 1973: Crude Expansion Facility
- OAC 120 (October 10, 1973): Crude Oil Storage Tanks (Tanks 4, 5, 6)
- OAC 179 (May 13, 1976): Slop Oil Vapor Control System including installation of an internal floating roof on Tank 14
- OAC 267 (March 25, 1982): Construction of Tank 20
- OAC 286 (April 17, 1984): Outside Coke Storage (duplicate OAC number)
- OAC 301 (June 14, 1985): Construction of three DCU Slop Oil Tanks (TK-15D-100A, -100B, and -100C)

### 4.1.3 Superseded Requirements

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

### 4.1.4 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 may 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 enforceable only by the state.

Most rules and requirements are followed by a date in parentheses. For the WAC regulations, the date listed in parenthesis in the air operating permit represents the State Effective date. For the NWCAA regulations, the date represents the most recent Board of Directors adoption date, which is identified as the "Passed" or "Amended" date in the NWCAA Regulation. The date associated with an OAC permit represents the issuance date of that new source review construction permit. For a federal rule, the date is the rule section's most recent promulgation date.

Two different versions (identified by the date) of the same regulatory citation may apply to the source if federal approval/delegation lags behind changes made to the Washington Administrative Code (WAC) or the NWCAA Regulation. As such, those citations that have been federally approved (i.e., incorporated into the SIP) are federally enforceable; the date listed is when it was incorporated into the SIP. If the rule has subsequently changed, those changes are enforceable only by the state or the NWCAA; the date listed is of the current version and is identified as "State Only".

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 become federally enforceable for the source.

### 4.1.5 Future Requirements

Applicable requirements that have been promulgated with future effective compliance dates may be included as applicable requirements in the AOP with a reference stating when compliance needs to be demonstrated. Some 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 addressed within the standard terms and conditions section of the AOP.

### 4.1.6 Alternative Operating Scenarios & Compliance Options

PSR did not request emissions trading provisions or specify more than one operating scenario in the AOP 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, except those approved by EPA (e.g., AMPs).

### 4.1.7 Gap Filling & 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).

The majority of 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.

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.

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 requirements 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 from 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 the 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 we found it was adequate to show compliance with the construction permit.

Table 4-1 lists where in the AOP NWCAA used its gap-filling monitoring authority.

**Table 4-1: Gap-filling under WAC 173-401-615**

| AOP Terms | Description | Monitoring |
|---|---|---|
| 4.2 | Operation & maintenance | Monitor, keep records & report |
| 4.3-4.11, 5.13.31 | Nuisance (contaminants, odors, PM, fugitives) | Written air contaminant response plan |
| 4.12-4.17 | 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 $H_2S$ |
| 4.22-4.23 | Sulfur in fuel | Retain fuel specifications & purchase records |

| AOP Terms | Description | Monitoring |
|---|---|---|
| 4.24 | Average $SO_2$ emission rate refinery-wide | Report average monthly lb/hr $SO_2$ |
| 4.26; 5.1.1; 5.1.2 | Equipment reduction, collection & disposal of VOC; noncondensable VOC reduction, collection & disposal - closed vent systems routed to flare; tightly covered hot wells - contact condensers | Written documentation of operation & maintenance activities |
| 5.2.5-5.2.6; 5.10.1 | Coke dust transport & handling; gasoline handling procedures; | Operate in accordance with written procedures consistent with good air pollution control practices |
| 5.10.5; 5.10.7; 5.10.9 | Submerged or bottom loading; connect vapor return lines;vapor control system alarm | Operate interlock system |
| 5.10.8 | Summertime failure of vapor collection | Recordkeeping |
| 5.10.10-5.10.11 | Vapor tight fittings | Keep design specifications & written procedures |
| 5.10.21 | Annual vapor tightness testing | Obtain vapor tightness documentation, record & cross-check. Maintain records of annual tank certification & continuous performance testing. Submit excess emission reports for nonvapor-tight tanks loaded. |
| 5.10.23 | Fuel loading restrictions | Maintain records of fuel loaded |
| 5.10.30; 5.13.14; 5.13.22; 5.14.4; 5.14.18; | Roof floating on surface | Records of periods when roof on leg supports; |
| 5.11.14 | flare mass flow meters with pressure & temperature compensation | Maintain documentation, update as necessary. Inspect meters annually, keep inspection records. |
| 5.13.11; 5.13.19; 5.14.6; 5.14.20 | Storage of organic liquid w/ 1.5 psia < TVP < 11.1 psia | Maintain TVP records, inspection frequency, inspection procedures, notice, recordkeeping & reporting requirements. |
| 5.13.12, 5.13.20, 5.14.2, 5.14.16 | Seal Coverage | Inspection frequency, gap measurement and inspection procedures, notice, recordkeeping & reporting requirements |
| 5.14.7; 5.14.21 | Storage of organic liquid MAX TVP | Maintain records of monthly max TVP at actual monthly average storage temperatures. Notify if actual max TVP exceeds thresholds in regulation. |
| 5.15.3; 5.15.4 | Spray coating enclosure requirements | Inspection frequency, procedures and recordkeeping. |
| 5.15.5 | Spray application method | Retain records documenting use of compliant methods. |
| 5.15.6 | Visible emission limit | Perform observations of effectiveness of capture and control of paint overspray, document use of dust collector if needed. Recordkeeping. |
| 5.15.7;5.15.8 | Equipment cleanup, closed containers, storage & disposal | Inspection frequency, inspection procedures and recordkeeping |
| 5.15.9 | Coating & solvent records | Record retention 5 years. |

| AOP Terms | Description | Monitoring |
|---|---|---|
| 5.15.10, 5.15.11 | Vapor-tight tank & sealed openings | Inspection frequency, inspection procedures, repairs and recordkeeping. |

Table 4-2 lists where in the AOP NWCAA used its sufficiency monitoring authority.

**Table 4-2: Gap-filling under WAC 173-401-630(1)**

| AOP Terms | Description | Monitoring |
|---|---|---|
| 4.1 | Required monitoring reports | Reporting periods identified |
| 5.1.14, 5.2.3, 5.7.13, 5.7.25, 5.8.10, 5.9.13, 5.9.23, 5.10.4, 5.12.5 | Visible emissions | VE observation monitoring |
| 5.7.21 | Fuel limitation | Records of fuel use |
| 5.9.8, 5.9.18 | Ammonia emissions | Annual RATA procedures + additional option for emissions less than 5 ppm |
| 5.10.14-5.10.18 | VOC control in vapor control system & transport tank | Biennial testing procedures & leak definition |
| 6.2.1; 6.2.2; 6.2.7; 6.2.8 | Pumps in light liquid service without dual mechanical seals; pumps in light liquid service with dual mechanical seals including a barrier fluid system; valves in gas/vapor service & in light liquid service – skip period monitoring program for valves; pumps & valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, & connectors | LDAR M21 calibration requirements for units complying with a lower leak definition |

## 4.2 Permit Elements

The air operating permit is organized in the following sequence:

- Permit Information
- Attest
- Table of Contents
- Section 1 - Emission Unit Identification
- Section 2 - Standard Terms and Conditions
- Section 3 - Standard Terms and Conditions for NSPS and NESHAP
- Section 4 - Generally Applicable Requirements
- Section 5 - Specific Applicable Requirements
- Section 6 – Commonly Referenced Requirements
- Section 7 - Inapplicable Requirements

AOP Sections 2 through 6 include citations to applicable requirements (e.g., regulations and OACs) and a summary of that requirement. In addition, AOP Sections 4 through 6 include the monitoring, recordkeeping and reports (MR&R) obligations for each requirement.

### 4.2.1 Permit Information and Attest Pages

The Information Page identifies the facility, the responsible corporate official, the agency personnel responsible for permit preparation, the date of permit issuance, and the due date for the renewal application. The Attest section provides NWCAA's authorization for the source to operate under the terms and conditions contained in the air operating permit.

### 4.2.2 Emission Unit Identification

AOP Section 1 entitled "Emission Unit Identification" is a non-enforceable section of the permit that is meant to list and provide 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.

### 4.2.3 Standard Terms and Conditions

AOP Section 2 entitled "Standard Terms and Conditions" contain administrative requirements and prohibitions in the State and the NWCAA regulations that do not generally have ongoing compliance monitoring requirements. The citations giving legal authority to the Standard Terms and Conditions are provided in the section. At times, requirements are paraphrased. In this case, the language of the cited regulation takes precedence over the paraphrased summary. For clarity and readability, the terms and conditions have been grouped by function. Similar requirements from the State and the NWCAA regulations are grouped together where possible. There are several requirements included that are not applicable until triggered. An example of these would be the requirement to file a "Notice of Construction and Application for Approval" prior to construction a new emissions source.

### 4.2.4 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), AOP Section 3, specifies administrative requirements or prohibitions with no ongoing compliance monitoring requirements. The conditions in this section are taken from the "General Provisions" of 40 CFR Parts 60, 61, and 63. They apply specifically to the affected sources, affected facilities, or stationary sources subject to the standards of 40 CFR Parts 60, 61, and 63.

### 4.2.5 Generally Applicable Requirements

AOP Section 4 entitled "Generally Applicable Requirements" identifies requirements that apply broadly facility-wide. These requirements are generally not called out in OACs and instead are found as general air pollution rules in the NWCAA Regulation or the Washington Administrative Codes.

When referring to the tables in AOP Sections 4, 5, and 6, the first column lists the AOP term number and pollutant or type (e.g., fuel use restriction) of requirement. The AOP terms are numbered consecutively to individually identify each requirement and so that the reader may easily locate a referenced term. Next, the citation column includes the legal citation which is a federally enforceable requirement unless listed as "State Only". The "description" column is a paraphrase of the requirement for informational purposes only; the language of the cited regulation takes precedence over a paraphrased requirement.

The last column lists the monitoring, recordkeeping and reporting (MR&R) requirements. The MR&R is a summary of the MR&R from the underlying requirements cited in the "citation" column and is not enforceable – the language of the cited regulation takes precedence over a paraphrased requirement. However, when there is text in the MR&R column that states "Directly Enforceable", all text below that statement has been added by NWCAA under the agency's gap-filling authority (discussed above), found in WAC 173-401-615(b) and WAC 173-401-630, and these gap-filled requirements are enforceable.

In some cases there are no MR&R or test methods listed in the AOP for a permit term. This is often due to the nature of the emission source, the lack of specifics in the underlying requirement, and/or the slim likelihood that the legal requirement will be violated. Note that the facility must certify annual compliance with each term even if there are no explicit MR&R requirements.

### 4.2.6 Specifically Applicable Requirements

AOP Section 5 entitled "Specifically Applicable Requirements" lists requirements that are specific to the individual emission units. Each table in AOP Section 5 represents a refinery process unit, area or grouping of similar emission units (e.g., reciprocating internal combustion engines). Within each table, emission units (EU) are presented in the order they are listed in AOP Section 1. As a general practice, general terms are presented first, followed by heaters, vents, heat exchangers, fugitive emission components, and lastly drains. For each emission unit, permit terms are generally presented in the following order: general, nitrogen oxides ($NO_X$), carbon monoxide (CO), sulfur dioxide ($SO_2$), visible emissions (VE), particulate matter ($PM/PM_{10}$), volatile organic compounds (VOC) and hazardous air pollutants (HAP).

The refinery uses CEMS to continuously monitor various emission units for gaseous pollutants including NOx and CO, as well as $H_2S$ and total reduced sulfur (TRS) as surrogates to $SO_2$. Where CEMS are used, continuous compliance with concentration limits, and to some extent mass emission rate limits, is relatively straightforward. Pollutants not continuously monitored, such as visible emissions, PM, $NH_3$ and VOC, are monitored periodically through visible emission observations and source testing and may be supplemented with continuous parameter monitoring to ensure on-going compliance.

The emission limitations and MR&R requirements are derived from the underlying requirements that are cited in the first column. 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.

### 4.2.7 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 SofB Section 2.2.12 for further discussion)
- Leak Detection and Repair (LDAR) program requirements from 40 CFR 60 Subpart VV (see SofB Section 2.1.2 under LDAR header for further discussion)
- Leak Detection and Repair (LDAR) program requirements from 40 CFR 60 Subpart VVa (see SofB Section 2.1.2 under LDAR header for further discussion)
- 40 CFR 60 Subpart QQQ requirements for individual drain systems (see SofB Section 2.1.2 under the wastewater header for further discussion)

- 40 CFR 63 Subpart DDDDD (Boiler MACT) requirements (see SofB Section 2.2.2 for further discussion)
- 40 CFR 63 Subpart CC requirements for heat exchangers (see SofB Section 2.1.2 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.

### 4.2.8 Inapplicable Requirements

WAC 173-401-640 requires the permitting authority issue a determination regarding the applicability of requirements with which the source must comply. The air operating permit lists requirements that are deemed inapplicable to the facility and the basis for each determination.

### 4.2.9 Insignificant Emissions Units

Table 4-3 below lists emission units present at PSR that are insignificant based their emission rate, size, or production rates in accordance with WAC 173-401-530 and -533. Column three of the table provides a justification for the exemption based on operational characteristics for each unit. Some categorically exempt insignificant emission units as defined in WAC 173-401-532 are present at PSR 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.

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 4-3: Insignificant Emission Units**

| Exempt Unit | WAC Citation | Comment |
|---|---|---|
| Amine Storage Tank 5JD2: DGA 100% | WAC 173-401-530(4) | Actual emissions are below the listed thresholds |
| Lean Amine Storage Tank 5JD205: DGA 40% | WAC 173-401-530(4) | |
| Lean Amine Storage Tank 5JD15: DGA 40% | WAC 173-401-530(4) | |
| Amine Regeneration Units | WAC 173-401-530(4) | |
| Lean MDEA Tank 17D101 | WAC 173-401-530(4) | |
| Wastewater Bullet Tank 105 (Sour water degassing drum) | WAC 173-401-530(4) | |
| Chevron Additive Tank (23ND12) | WAC 173-401-530(4) | |
| Exxon Additive Tank (23ND3) | WAC 173-401-530(4) | |
| Generic Additive Tank (23ND13) | WAC 173-401-530(4) | |
| Shell Additive Tank (23ND11) | WAC 173-401-530(4) | |
| HiTech Additive Tank (23ND4) | WAC 173-401-530(4) | |
| Dock Clean System 3 Trailer: 600 gallons | WAC 173-401-530(4) | |
| Dock Foam Tank: 4,500 gallons | WAC 173-401-530(4) | |
| Propane Bullets Odorant Tank (21ND4): 3,000 gallons | WAC 173-401-530(4) | |
| TTLR Odorant Tank (23NC20): 1,000 gallons | WAC 173-401-530(4) | |
| TTLR Foam Tank (23ND7): 600 gallons | WAC 173-401-530(4) | |
| TCLR Odorant Tank (23NC21): 1,000 gallons | WAC 173-401-530(4) | |

| Exempt Unit | WAC Citation | Comment |
|---|---|---|
| TCLR R620 Lubricity Additive (23NC26): 6,507 gallons | WAC 173-401-530(4) | |
| EP Polymer Tank: 2,000 gallons | WAC 173-401-530(4) | |
| EP Tank S-16 Biosolids Transfer Tank: 1,096 bbls | WAC 173-401-530(4) | |
| Tank 63 (corrosion inhibitor) | WAC 173-401-530(4) | |
| Tank 65 (cold flow improver) | WAC 173-401-530(4) | |
| Tanks 66 and 77 (12% bleach): 148 gallons each | WAC 173-401-530(4) | |
| Tank 67 (Morton Automate dye) | WAC 173-401-530(4) | |
| Tank 68 (Diesel ignition improver) | WAC 173-401-530(4) | |
| Tank 69 (Automate red dye) | WAC 173-401-530(4) | |
| Tank 7 (Crude oil safety confinement tank) | WAC 173-401-530(4) | |
| Emergency 100-kW Steam Generator (unit powered by steam) | WAC 173-401-530(4) | |
| Emergency 200-kW Steam Generator (unit powered by steam) | WAC 173-401-530(4) | |
| Amine Storage Tank Tank 104 (Vapors to flare system after being scrubbed with lean DGA) | WAC 173-401-530(4)(q) | |
| Amine Pit with Vent Sorb 5JD16 (Amine pit air emissions are controlled with a charcoal scrubber) | WAC 173-401-530(4)(q) | |
| Garage Diesel Fuel Tank: 1,000 gallons underground storage tanks for plant vehicle use | WAC 173-401-533(2)(c) | Capacity less than 10,000 gallons and vapor pressure less than 80 mmHg at 21°C |
| Boiler House Storage Tank 31G-D12: 6,000 gal 50% NaOH | WAC 173-401-533(2)(s) | Tanks, vessels, and pumping equipment, with lids or other appropriate closure for storage or dispensing of aqueous solutions of inorganic salts, bases and acids |
| Boiler House Storage Tank 31G-D11: 3,000 gal sodium sulfite | WAC 173-401-533(2)(s) | |
| Boiler House Water Conditioning Tanks 31G-D14, 31G-D15, 31G-C8, 31G-C7, 31G-C37A, 31G-C37B, 31G-C37C | WAC 173-401-533(2)(s) | |
| VPS Caustic Storage Tank | WAC 173-401-533(2)(s) | |
| CPU Caustic Storage Tank 5JD1 | WAC 173-401-533(2)(s) | |
| Spent Caustic Tanks 301, 303, and 305 | WAC 173-401-533(2)(s) | |
| Fresh Caustic Tanks 302 and 304 | WAC 173-401-533(2)(s) | |
| EP Caustic Totes | WAC 173-401-533(2)(s) | |
| EP Acid Tank 9QD22: 6,000 gallons | WAC 173-401-533(2)(s) | |
| EP Caustic Storage Tank 9NQD 23 | WAC 173-401-533(2)(s) | |
| Caustic Railcar Loading System | WAC 173-401-533(2)(s) | |
| Fresh Acid Storage Tanks 401 & 404: 42,000 gallons each | WAC 173-401-533(2)(s) | |
| Spent Acid Storage Tanks 402 & 403: 42,000 gallons each with nitrogen blanket for explosion control with vapors vented to the flare header | WAC 173-401-533(2)(s) | |

| Exempt Unit | WAC Citation | Comment |
|---|---|---|
| DCU Tank 15D-102 (slop oil/sour water system) | WAC 173-401-533(2)(s) | |
| Stormwater System | WAC 173-401-533(3)(d) | NPDES permitted ponds and lagoons utilized solely for the purpose of settling suspended solids and skimming of oil and grease |
| Spill Basin | WAC 173-401-533(3)(d) | |

### 4.3 Public Docket

Copies of PSR's Air Operating Permit, permit application, and technical support documents are available online at www.nwcleanairwa.gov or at the following location:

Northwest Clean Air Agency
1600 South Second Street
Mount Vernon, WA 98273-5202

### 4.4 Definitions and Acronyms

Definitions are assumed to be those found in the underlying regulation. A short list of definitions has been included to address 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 Department of Ecology.

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

| | |
|---|---|
| AAG | Amine acid gas |
| Alky | Alkylation unit |
| AMP | Alternative Monitoring Plan |
| AOP | Air Operating Permit |
| API | American Petroleum Institute |
| ARU | Amine Regeneration Unit |
| ASTM | American Society for Testing and Materials |
| Avjet | Aviation jet fuel |
| BACT | Best available control technology |
| BBL | Barrel (42 US gallons) |
| BHU | Butadiene Hydrogenation Unit |
| BOHO | Boiler House |
| BRU | Benzene Reduction unit |
| Btu | British thermal unit |
| BQ6 | Benzene waste Quantity under 6 Mg/yr (wastewater) |

| | |
|---|---|
| BWON | Benzene Waste Operations NESHAP |
| CAA | Clean Air Act |
| CAM | Compliance Assurance Monitoring |
| CDHDS | Catalytic Distillation Technology Hydrodesulfurization |
| CEM | Continuous emission monitor |
| CEMS | Continuous emission monitoring system |
| CD | Consent Decree |
| CI | Compression ignition (internal combustion engine) |
| CFM | Cubic feet per minute |
| CO | Compliance Order |
| COB | Carbon monoxide (CO) boiler |
| Cogen | Cogeneration units |
| COM | Continuous opacity monitor |
| CFR | Code of Federal Regulations |
| CPU | Catalytic Polymerization Unit |
| CRU | Catalytic Reforming Unit |
| DAF | Dissolved Air Flotation (wastewater) |
| DCH | Decyclohexanizer |
| DCU | Delayed Coking Unit |
| Debut | Debutanizer |
| EFR | External Floating Roof (tank) |
| EP | Effluent Plant |
| EPA | Environmental Protection Agency |
| ERC | Emission reduction credit |
| ESP | Electrostatic precipitator |
| FCAA | Federal Clean Air Act |
| FCCU | Fluid Catalytic Cracking Unit |
| FGR | Flue Gas Recirculation or Flare Gas Recovery |
| HAP | Hazardous Air Pollutants |
| HC | Hydrocarbon |
| HHV | Higher Heating Value (heat content of fuel) |
| HON | Hazardous Organic NESHAP |
| HTU | Hydrotreater Unit |
| $H_2S$ | Hydrogen sulfide |
| $H_2SO_4$ | Sulfuric acid |
| hp | Horsepower, brake |
| HRSG | Heat recovery steam generator |
| HSR | Heavy Straight Run |
| ICE | Internal Combustion Engine |
| IFR | Internal Floating Roof (tank) |
| ISO | International Standards Organization |
| ISOM | Isomerization unit |
| kPa | Kilopascals ($10^3$ pascals pressure) |
| LDAR | Leak detection and repair |
| LNB | Low-NOx Burner |
| LEL | Lower explosive limit |
| LPG | Liquefied petroleum gas |

| | |
|---|---|
| LTPD | Long tons per day (imperial ton, 2,240 pounds) |
| MACT | Maximum Achievable Control Technology |
| MDEA | Methyl-diethanolamine |
| Mg | Megagrams ($10^6$ grams mass) |
| MMBtu | Million British thermal units |
| MMSCFD | Million standard cubic feet per day |
| MPCC | March Point Cogeneration Company |
| MPV | Miscellaneous process vent |
| MR&R | Monitoring, recordkeeping, and reporting requirements |
| MTVP | Maximum true vapor pressure |
| MV | Maintenance vent |
| NIST | National Institute of Standards and Technology |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NOC | Notice of Construction |
| $NO_X$ | Oxides of nitrogen |
| NPDES | National Pollutant Discharge Elimination System |
| NSPS | New Source Performance Standard |
| NSR | New source review |
| NWCAA | Northwest Clean Air Agency |
| $O_2$ | Oxygen |
| OAC | Order of Approval to Construct |
| PM | Particulate matter |
| $PM_{10}$ | Particulate matter less than 10 microns in diameter |
| $PM_{2.5}$ | Particulate matter less than 2.5 microns in diameter |
| Poly | Catalytic Polymerization Unit (aka CPU) |
| ppmvd | Part per million by volume, dry |
| ppmw | Part per million by weight |
| psia | Pounds per square inch absolute |
| PTE | Potential to Emit (annual, unless otherwise noted) |
| PRD | Pressure relief device |
| PSR | Puget Sound Refinery |
| QA/QC | Quality assurance/quality control |
| RCW | Revised Code of Washington |
| RICE | Reciprocation internal combustion engine |
| RO | Regulatory Order (issued by the NWCAA) |
| RP&S | Receiving, pumping, and shipping |
| SCF | Standard cubic feet |
| SCFM | Standard cubic feet per minute |
| SCR | Selective catalytic reduction |
| SEPA | State Environmental Policy Act |
| SIP | State Implementation Plan |
| SofB | Statement of Basis |
| SOCMI | Synthetic Organic Chemical Manufacturing Industry |
| SOP | Standard operating procedure |
| SR | Straight run |
| SRU | Sulfur Recovery Unit |
| SWS | Sour Water Sewer |

| | |
|---|---|
| $SO_2$ | Sulfur dioxide |
| TAB | Total annual benzene |
| TCLR | Train car load rack |
| TGTU | Tail gas treating unit |
| TPY (tpy) | Tons per year |
| TRS | Total reduced sulfur |
| TTLR | Tank truck load rack |
| TVP | True vapor pressure |
| ULNB | Ultra-low NOx burner (designed for ≤ 0.04 lb/MMBtu) |
| ULSD | Ultra low sulfur diesel |
| VE | Visible emissions |
| VP | Vapor pressure |
| VPS | Vacuum Pipe Still (Crude Unit) |
| VOC | Volatile organic compounds |
| VOL | Volatile organic liquid |
| WAC | Washington Administration Code |
| WDOE | Washington Department of Ecology (Ecology) |
| WGS | Wet Gas Scrubber |
| WWSG | Waste Water Stripper Gas |

# APPENDIX A

## 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 SofB (SofB Section 1.2).

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.

**AOP #014R1M1 issued 5/10/15 – changes made due to administrative amendment**

On March 27, 2015, The NWCAA received a request from Shell Puget Sound Refinery for an administrative amendment to the first renewal AOP. On May 5, 2015, AOP #014R1 was revised as allowed in WAC 173-401-720(1)(b), including renumbering the permit to #014R1M1, updating the issuance date, and changing the responsible official to Shirley Yap, General Manager.

**AOP #014R1 issued 11/5/18 – changes made during 1st renewal**

Equilon Enterprises LLC dba Shell Oil Products US took full possession of the adjacent cogeneration units formerly owned and operated by the March Point Cogeneration Company (MPCC) on February 1, 2010. Rolled the requirements for the cogeneration units (MPCC) (AOP 005R1) into the refinery AOP.

Removed the Consent Decree compliance schedule from the AOP. A brief summary of the Consent Decree(s) is included in this Statement of Basis.

Replaced the references to NWCAA 365, 366 and the "Guidelines for Industrial Monitoring Equipment and Data Handling" with NWCAA 367 and NWCAA Appendix A - "Ambient Monitoring, Emission Testing and Continuous Emission and Opacity Monitoring" in the paragraphs preceding the table of requirements. NWCAA 367 and NWCAA Appendix A have been updated to include current monitoring technology and methods but are not materially different from the previous rule and guideline.

Changed the "gap filling" marker in the MR&R column tables from "Directly enforceable under WAC 173-401-615(1)(b) & (c), 10/17/02." to "Directly Enforceable."

**Permit Information Page**

Updated the source contact information and general permit information.

**AOP Section 1**

Revised to reflect the current list of emission units and regulatory applicability:

Added heat exchangers pursuant to 40 CFR 63 Subpart CC.

Fixed roof storage Tank 203 has been demolished and was removed from the AOP.

**AOP Sections 2 and 3**

Revised to be consistent with current NWCAA format and content.

Updated citations and dates as appropriate.

**AOP Sections 4 and 5**

Revised to include current federal, state and NWCAA regulatory citations and their applicable requirements to reflect any new or revised applicable regulation, include but are not limited to:

Added and/or revised the following New Source Performance Standards (NSPS)

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

According to a letter from PSR dated October 13, 2004, PSR conducted a review pursuant to the Equilon Consent Decree and determined that Tanks 12, 13, 14, 60, 61, 62, 70, 71, 72, and 73 are subject to 40 CFR 60 Subpart Kb. Added Subpart Kb applicability to listed tanks.

Added 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

Added 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Added and/or revised the following National Emission Standards for Hazardous Air Pollutants (NESHAP):

PSR converted Tank 74 from an equalization tank prior to the bioreactor to a preliminary bioreactor equipped with blowers and fed with the same biota as the traditional bioreactor. Because it is no longer part of the wastewater treatment unit, the tank is no longer subject to 40 CFR 61 Subpart FF requirements.

The Marine Terminal was considered not subject to 40 CFR 63 Subpart Y (National Emission Standards for Marine Tank Vessel Loading Operations) and that regulation was included in the inapplicable requirements. Technically, the Marine Terminal was subject to 40 CFR 63 Subpart Y as an existing offshore loading terminal but had no requirements. 40 CFR 63 Subpart Y was modified on April 21, 2011 such that existing offshore loading terminals must meet the submerged fill standards. This requirement is listed in AOP Section 5.10.

Explicitly incorporated 40 CFR 63 Subpart UUU requirements.

Tank 64 stores a fuel additive and has been added to the Receiving, Pumping, and Shipping (RP&S) Unit in AOP Section 1.10.5. Apparently this tank has always been on the site, but was not included previously. Tank 64 is subject to 40 CFR 63 Subpart EEEE (Organic Liquid Distribution) but had no requirements. However, 40 CFR 63 Subpart EEEE was modified on April 23, 2008 such that tanks such as Tank 64 are required to keep documentation that verifies the storage tank is not required to be controlled. This requirement is listed in the AOP Section 5.10.

Internal Floating Roof Tank 54 changed service from diesel to gasoline in 2009. Went from 40 CFR 60 Subpart CC (Refinery MACT 1) Group 2 to Group 1 service.

Added 40 CFR 63 Subpart ZZZZ -Stationary Reciprocating Internal Combustion Engines

Added 40 CFR 63 DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters

Added 40 CFR 63 Subpart GGGGG – Site Remediation (recordkeeping only)

Added 40 CFR 64 Compliance Assurance Monitoring (CAM) to Section 5 reflecting the CAM plan submitted by the refinery.

Revised Section 5 with new or revised orders (i.e., OAC, ROs, and COs). These include but are not limited to:

Tank 76 was incorrectly listed as being permitted under OAC 345. This tank was constructed as part of project to automate cleanout of the API in the early 1990s. This tank was never placed into service and is currently not being used.

RO17 was an Emission Reduction Credit (ERC) issued on September 14, 1995 for the installation of an internal floating roof on Tank 30. ERCs expire after 10 years; as such, RO17 expired in 2005 and is removed from the AOP.

According to OAC 919 Condition 8 and OAC 929a Condition 8, upon issuance of both OAC 919 and 929a and upon installation of the emission controls required by the Heater and Boiler Consent Decree and both OACs, NWCAA Revised Regulatory Order and Emission Reduction Credit 20b is superseded and no longer in effect. The controls required by OAC 919 and OAC 929a have both been completed; as such, all of the conditions related to Regulatory Order 20b are removed from the AOP.

The NWCAA issued RO21 on April 14, 2000 establishing a voluntary NOX emission limit on the Erie City Boiler. The NWCAA rescinded this Order on October 10, 2012 upon request by PSR because these limits are no longer desired.

On April 14, 2000, two regulatory orders (ROs 22 and 23) were issued by the NWCAA to create a federally enforceable voluntary cap on NOX emissions at CRU2. The NWCAA rescinded these orders on October 10, 2012 upon request by PSR because these limits are no longer desired.

On April 14, 2000, Regulatory Order 24 was issued establishing a voluntary NOX limit of 32 tons based on a 12-month rolling average and 7.5 tons per hour limit based on a daily average. The NWCAA rescinded this Order on October 10, 2012 upon request by PSR because these limits are no longer desired.

On April 14, 2000, the NWCAA issued Regulatory Order 25 thereby establishing a voluntary NOX limit from all three flares combined to 2,200 lb/hour, daily average. The NWCAA rescinded this Order on October 10, 2012 upon request by PSR because these limits are no longer desired.

Included Compliance Order (CO) 07 to memorialize the Heater and Boiler Consent Decree mandate that subject refinery heaters and boilers are subject to 40 CFR 60 Subpart J.

Included CO 08 to memorialize the requirement to install and maintain a cover on the slotted guidepole opening on Tank 38 resulting from the Storage Tank Emission Reduction Partnership Agreement with EPA.

Included CO 10 to memorialize the Equilon Consent Decree mandates related to the FCCU.

The existing 555 hp EP Emergency Outfall Pump engine was decommissioned in 2013 and replaced with the 500 hp EP Outfall Pump engine. The same pump is being used with the new engine; the unit is keeping the same 9QG68 designation.

The Light hydrocarbon slop degassing drum vent (21N-C110) has been reclassified as being subject to 40 CFR 61 Subpart FF. As such, it is not a Miscellaneous Process Vent (MPV) under 40 CFR 60 Subpart CC. The requirements for this vent are covered under the Effluent Plant and Sewer System (AOP Section 5.13.1). Removed individual reference to this vent as MPV from the AOP.

**AOP Section 6**

Revised with current federal, state and NWCAA regulatory citations and their applicable requirements to reflect any new or revised applicable regulation. These include but are not limited to adding and/or revising the following:

Removed the visible emission ongoing compliance demonstration for combustion units while firing oil in AOP Section 6. None of the process units are currently configured to fire oil; if PSR were to want the ability to fire oil, it would constitute a modification and require review under New Source Review. The Cogens are allowed to fire both avjet and low sulfur diesel; the ongoing compliance demonstration for which is handled in AOP Section 5.

Added 40 CFR 60 Subpart VVa - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry – Common leak detection and repair requirements

Added 40 CFR 60 Subpart QQQ – Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems – Common individual drain systems requirements

Added 40 CFR 63 Subpart DDDDD— National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters – Common boiler and heater requirements

Added 40 CFR 63 Subpart CC — National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries – Common heat exchanger requirements

**AOP Section 7**

Merged and revised the list of inapplicable requirements into one refinery-wide list.

**AOP #014M1 issued 9/24/04 – changes to initial permit due to significant modification**

PSR submitted requests to modify the AOP on August 18, 2003, February 9, 2004, and May 3, 2004. The AOP was modified and re-issued on September 24, 2004 (AOP 014M1).

The permit was modified to incorporate OAC 772a (BHU), OAC 630a (HTU2), OAC 787b (HTU3) and OAC 828 (SRU4). Changes were made to include upgrades to the flare system consistent with the EPA's consent decree approved hydrocarbon flaring reduction plan as a method for meeting 1000-ppm $SO_2$ limits for flares. And, 40 CFR 63 Subpart A requirements for flares were added to Section 5.10.

# APPENDIX B

CAM Plan for Particulate Matter Grain Loading Limit at the FCCU/WGS

# CAM Monitoring Plan for the FCCU PM10 grain loading limit
# June 2013

## 1.0 WGS Particulate Emissions

Condition 1a of NWCAA OAC 623e limits the WGS Stack particulate emissions (PM-10) to 0.02 grains/SCF (basis dry, corrected to 7% O2).

During each annual WGS Performance Test, the actual WGS particulate emissions are measured as required by condition 2 of NWCAA OAC 623e.

From these WGS Performance Test results, the WGS particulate concentration (basis dry, corrected to 7% O2) is determined.

This baseline WGS particulate concentration is identified by the online computer tag **3WGSPM10BaselineDryPct7**, which is used when calculating PM-10 mass emissions.

*The value of **3WGSPM10BaselineDryPct7** will need to be updated annually with the results of the annual source test as follows*,

**3WGSPM10BaselineDryPct7 = source test value (grains/SCF, basis dry, corrected to 7% $O_2$)**

Condition 1b of the NWCAA OAC 623e limits the WGS Stack particulate mass emissions (PM-10) to 202 tons per rolling 12-month period. Condition 3 of NWCAA OAC 623e requires that PSR continuously calculate and determine compliance with the WGS PM-10 mass emissions. The PM-10 tons per year will be calculated using the most recent source test value, as described above, and are identified as the computer variable **3PM10WGS**. Its units are lb/hr:

**3PM10WGS =** (1000*3DryWGSStackFlowPct7)*(3WGSPM10BaselineDryPct7/7000)

Where **3DryWGSStackFlowPct7** is the continuously calculated variable for the WGS stack flow, corrected to 7% excess O2, in units of MSCFH.

## 2.0 WGS Efficiency Monitoring

Refinery MACT regulations use opacity as a surrogate parameter to show continuous compliance with the PM standards. Because the gases emitted from the WGS Stack are saturated with water vapor, it is not practical to monitor stack emissions with an opacity meter. Therefore, the USEPA has approved an alternative monitoring plan (AMP) to demonstrate proper operating efficiency for the Puget Sound Refinery's WGS Stack.

The efficiency of the Wet Gas Scrubber will be monitored using the ratio of the Caustic Circulation to Inlet Flue Gas Flow. This same efficiency factor can be used to show continuous compliance with the 0.02 grain loading limit referenced in the previous section.

$$\textbf{L/G ratio} = \frac{\textbf{Volumetric liquid flow rate of the caustic stream to the gas scrubber}}{\textbf{Dry volumetric flow rate of gases to the gas scrubber}}$$

The EPA approved AMP has stipulated that the L/G ratio have units of measure of (gpm/mscfh) and given by the following equation,

**3WGSLGRatio = 3FI366.pv/(3WGSFactorPerfTest*3DryWGSStackFlow)**

where,

**3FI366.pv** is the measured volumetric flow rate of the caustic to the gas scrubber (GPM)

**3DryWGSStackFlow** is the calculated volumetric flow rate (dry basis) of the WGS Stack gases (MSCFH)

**3WGSFactorPerfTest** is a factor determined during the annual WGS Performance Test.

This factor is the ratio of two values for the dry WGS Stack gas flow(both in MSCF/HR).

The numerator is the value of the dry WGS Stack flow determined by the Stack Testing Contractor performing the Annual WGS Environmental Performance Test. The denominator is the average value of 3DryWGSStackFlow calculated by the PSR online system during the same time period used for the Environmental Contractor's calculation.

**WGSFactorPerfTest** is calculated from the annual Performance Test as follows:

$$\frac{\textbf{[Contractor Value of WGS Dry Stack Flow in SCF/Min]*60/1000}}{\textbf{Average Value of PSR Computer Tag “3DryWGSStackFlow” in MSCF/Hr}}$$

*Then the variable **3WGSFACTORPERFTEST** is updated annually in the online system.*

The minimum limit for **3WGSLGRatio** is established at the initial WGS Performance Test which establishes the minimum ratio needed to maintain compliance (compliance is based on a minimum value – a higher L/G ratio will provide better efficiency). If this tag reads below the minimum value an alarm will activate and plant personnel will take corrective action to prevent any deviation from the limit. Computer tags **3WGSLGRatio** and **3WGSLGRatioRoll3Hr** are used for continuous compliance monitoring.

**3WGSLGRatio Minimum Limit = 0.93**

# APPENDIX C

## RESPONSE TO COMMENTS

The Northwest Clean Air Agency (NWCAA) will accept comments on the second renewal of the Shell Puget Sound Refinery (PSR) Air Operating Permit (AOP) from June 25, 2021, through close of business July 26, 2021.

No comments were received by NWCAA during the public comment period for the AOP 014R2.