

Statement of Basis for the
Air Operating Permit
- Final -

**BP West Coast Products LLC
Cherry Point Refinery**

Blaine, Washington

August 26, 2014



Serving Island, Skagit & Whatcom Counties

PERMIT INFORMATION

BP Cherry Point Refinery

4519 Grandview Road, Blaine, WA

SIC: 2911

NAICS: 324110

EPA AFS: 53-073-10007

NWCAA ID: 1011-V-W

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Application Date:	Renewal Application Due:
December 14, 2007	January 15, 2017

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1 INTRODUCTION AND GENERAL FACILITY DESCRIPTION

The BP Cherry Point Refinery, owned by BP West Coast Products LLC, is required to obtain an Air Operating Permit (AOP or permit) because it has the potential to emit the following:

- 100 tons or more per year of oxides of nitrogen (NO_x), sulfur dioxide, particulate matter and carbon monoxide;
- 10 tons per year or more of any hazardous air pollutant; and
- 25 tons or more per year of a combination of hazardous air pollutants.

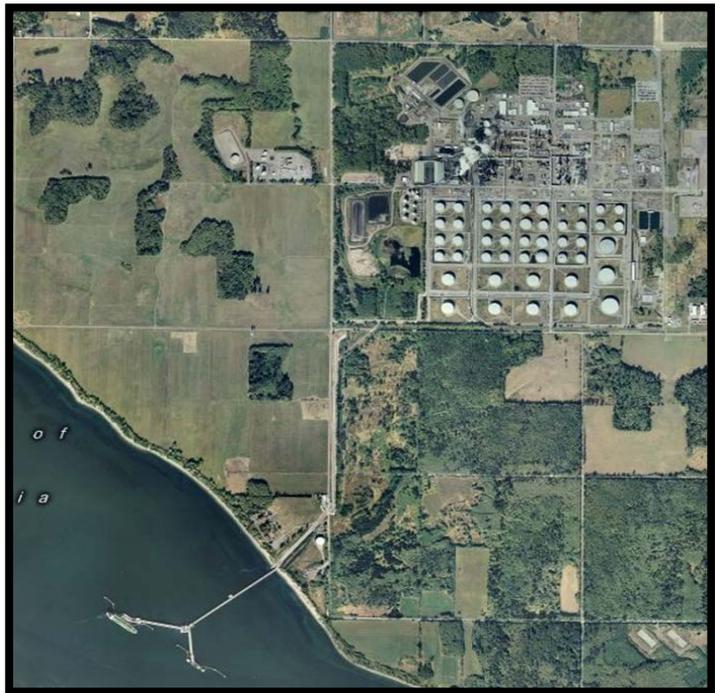
The purpose of this Statement of Basis (SOB) is to set forth the legal and factual basis for the terms of the Air Operating Permit (AOP) issued to the BP Cherry Point Refinery under the authority of the Washington Clean Air Act, Chapter 70.94 Revised Code of Washington (RCW), Chapter 173-401 of the Washington Administrative Code (WAC), and Northwest Clean Air Agency Regulation Section 322. Unlike the permit, this document is not legally enforceable in accordance with WAC 173-401-700(8). It includes references to the applicable statutory or regulatory provisions that relate to the Cherry Point Refinery's air emissions and provides background information to facilitate review of the permit by interested parties.

1.1 Facility Description

The Cherry Point Refinery produces petroleum-based fuels as classified under the Standard Industrial Classification code 2911 for this activity. BP West Coast Products LLC owns and operates the Cherry Point Refinery in Blaine, Washington. The refinery was originally built in 1970 by the Atlantic Richfield Company (ARCO). In April 2000, BP acquired ARCO and effective January 1, 2002; ARCO transferred all of its retail and refining assets, including the Cherry Point Refinery, to its new affiliate, BP West Coast Products LLC.

The surrounding area is designated in attainment for all National Ambient Air Quality Standards (NAAQS). The refinery is located in a rural setting zoned for heavy industrial use. The surrounding land use is agricultural. Immediately to the west of the refinery is the Puget Sound Energy's Whitehorn Generating Station comprised of a gas turbine peaking power generating station. Alcoa Aluminum Corporation and the Phillips66 refinery are located south of the refinery. Approximately two miles north of the refinery is the community of Birch Bay.

The Cherry Point Refinery has a crude oil distillation capacity of 234,000 barrels per day¹. The refinery receives crude oils via marine tanker, rail car, and pipeline. The refinery produces a wide variety of products including gasoline, diesel, jet fuel, green coke, calcined coke, liquefied petroleum gas (LPG), butane, pentane, elemental sulfur as well as intermediates such as reformate. Products are sent to market in several

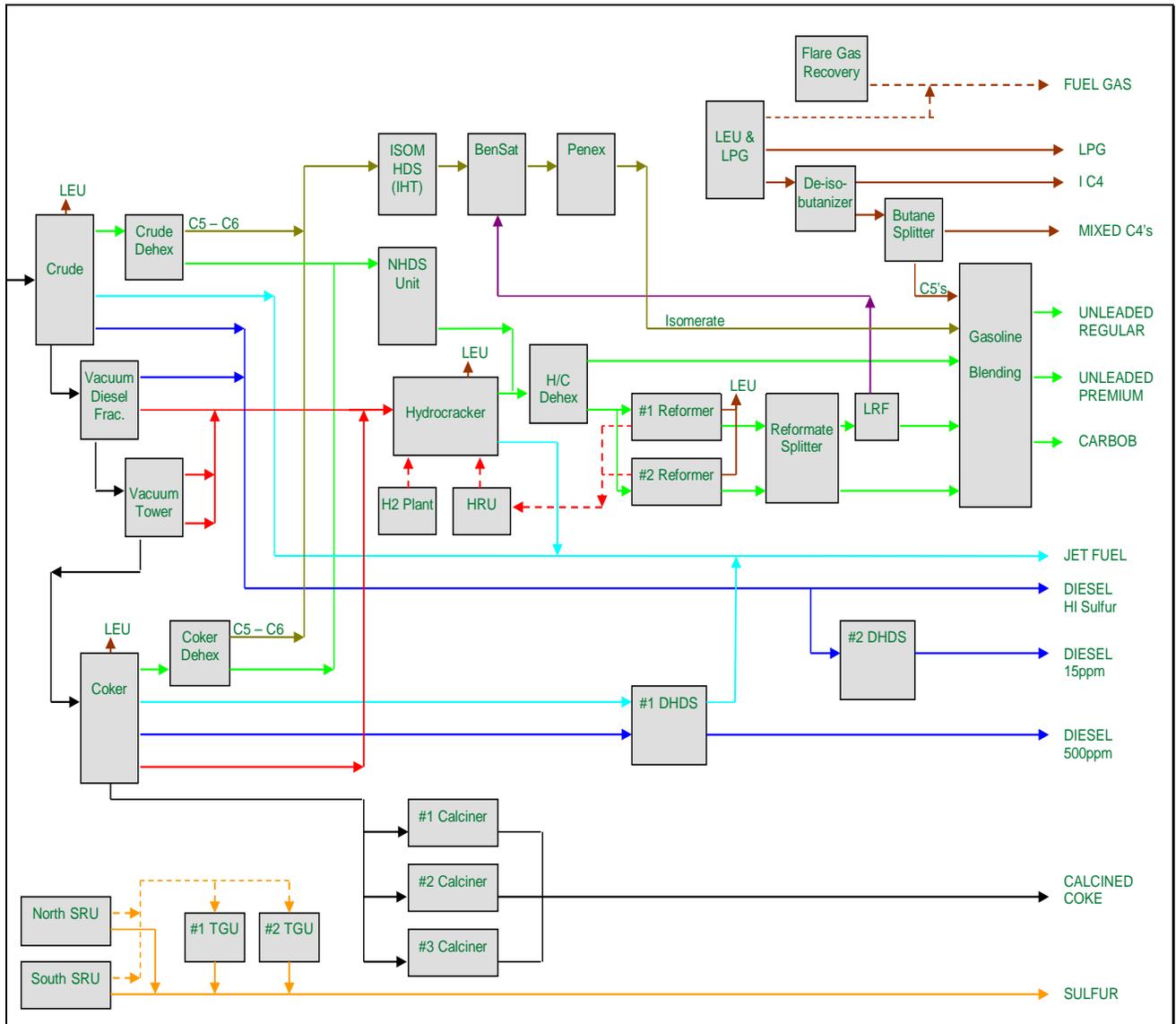


¹ Source: Oil & Gas Journal, 5/10/13 article, titled *BP starts Cherry Point diesel hydrotreater*.

ways. Marine vessels and barges are used to ship gasoline, diesel jet fuel and intermediates. Pipelines are used to distribute gasoline, diesel, and jet fuel. Rail cars are used to distribute LPG, butanes, sulfur, green coke, and calcined coke. And, trucks are used to distribute LPG, gasoline, diesel, jet fuel, calcined coke, and sulfur.

For the purposes of this SOB and the AOP, refinery processes are grouped into logical areas either by process unit or by geographical areas within the refinery. Section 1 of the permit presents a list of the process units/areas at the Cherry Point Refinery. Each major emission unit such as each heater and boiler has an associated equipment number. This identification number begins a number identifying the process unit or area followed by the equipment number. The maximum firing rate capacity in million Btu per hour (MMBtu/hour) for each heater and boiler is included in Section 1 of the permit. These firing capacities are derived from NWCAA construction permit documents, or when this information is not available, from the refinery's CY 2010 greenhouse gas emission report.

The process flow diagram presented below represents the interrelationship between process units within the refinery excluding the #3 DHDS Unit or the #2 Hydrogen Plant that were under construction in 2012.



All of the process heaters and utility boilers at the refinery are fueled by gasses generated at the refinery. Refinery fuel gas is also used for supplemental firing at the Sulfur Recovery Complex Incinerator and for supplemental firing of the #1, #2 and #3 Calciners to generating steam when calcining operations are curtailed. Refinery fuel gas is typically generated as a by-product of the light gasses separated at the top portions of distillation towers that are located throughout the refinery. These gasses are collected and amine scrubbed to remove H₂S prior to distribution to the combustion devices.

There are three distinct refinery fuel gas streams at the Cherry Point Refinery. The main refinery fuel gas system collects gasses from all of all processing units except the Delayed Coker. The gasses are combined and mixed in the main mix drum before being routed to combustion devices throughout the refinery. When the refinery is low with regard to fuel gas generation, purchased natural gas is used to supplement the volume of gas in the main mix drum. The second refinery fuel gas stream is produced at the Delayed Coker and for the most part combusted in the North and South Coker Charge Heaters located at the Delayed Coker. The Delayed Coker fuel gas is rich in sulfur bearing mercaptans that are not removed during amine scrubbing. The third refinery fuel gas stream is vacuum tail gas that is produced in the vacuum section of the Crude and Vacuum Unit. The vacuum tails gas stream is relatively small in volume but rich in sulfur compounds. The vacuum tail gas is combusted in the Crude Heater along with fuel gas from the main mix drum.

The Delayed Coker fuel gas system and main refinery mix drum and are linked so that if one is short on fuel gas, it be supplied by the other fuels gas system. Under normal refinery operations the Delayed Coker generates excess fuel gas and supplements the supply of gas to the main refinery mix drum. Because the fuel gas generated at the Delayed Coker is characteristically high in non-H₂S sulfur compounds such as mercaptans, it increases SO₂ emission rates from fuel gas combusted throughout the refinery.

1.2 Permit Revisions during First Renewal

The NWCAA received the application for the first air operating permit renewal on December 14, 2007. The following revisions have been made to the permit during this renewal.

- Revised the source contact information and general permit information on the permit information page.
- Revised Section 1 to reflect the current list of emission units.
- Revised Sections 2 and 3 to be consistent with current NWCAA format and content.
- Revised Sections 4 and 5 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 the following New Source Performance Standards (NSPS)

- 40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
- 40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006
- 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Adding the following National Emission Standards for Hazardous Air Pollutants (NESHAP)

- 40 CFR 63 Subpart EEEE - Organic Liquids Distribution, Small Tanks and Racks (recordkeeping only)

- 40 CFR 63 Subpart ZZZZ -Stationary Reciprocating Internal Combustion Engines
- 40 CFR 63 DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters
- 40 CFR 63 Subpart GGGGG – Site Remediation (recordkeeping only)
- Revised Section 5 with new or revised construction orders (i.e., OAC and PSD permits). This includes four new and 27 revised Orders of Approval to Construct issued by the NWCAA, and one new and three amended Prevention of Significant Deterioration permits issued by Ecology.
- Revised Section 5 to include a Best Available Retrofit Technology (BART) Order issued Ecology.
- Added 40 CFR 64 Compliance Assurance Monitoring (CAM) to Section 5 reflecting CAM plans submitted by the refinery.
- Added the following items to the common requirements of Section 6.
 - The leak detection and repair provisions of 40 CFR 60 Subpart VVa
 - Requirements related to particulate and SO₂ limits of OAC 211c
- Revised the list of inapplicable requirements in Section 7.
- Removed the BP 2001 Consent Decree compliance schedule from the permit. A summary of the Consent Decree is included in this Statement of Basis.

1.3 Enforcement History

A summary of Notices of Violation issued to the refinery by the NWCAA from January 2007 through September 2012 is presented below. Each violation listed in the table has been resolved through a combination of penalty assessments and by corrective action taken by the source.

Table 1-1: Notice of Violations Issued to the Cherry Point Refinery

Case No	Violation Date	Issue Date	Description
3579	1/31/07	3/8/07	Operating uncontrolled benzene waste streams generated from draining loading arms into sump tanks located on the north and south docks of the marine terminal. Penalty paid \$47,500.
3597a	4/30/07	6/1/07	Interruption of the feed rate to the Hydrocracker Unit causing a depressurization of the 1st Stage Reactor to the high pressure flare. Flared emissions exceeded the SO ₂ limit of 1000 ppm. SO ₂ emissions over the limit were estimated at 1,161 lb for the 21.5 hour event. Penalty paid \$10,000.
3650	6/14/07	11/5/07	CO limit for the North Coker Heater exceeded during source testing. Penalty paid \$7,000.
3751a	10/7/08	4/6/09	Failure to conduct a source test for PM ₁₀ and H ₂ SO ₄ on the #3 Calciner WESP stack within eleven to thirteen months of the anniversary date of the previous test. The test was conducted two months late. In addition, a test plan was not submitted in accordance with NWCAA Appendix A. Penalty paid \$2,000.
3761	1/27/09	4/20/09	Flared emissions exceeding the 1,000 ppm, corrected to 7% oxygen, 60-minute average limit caused from an inadvertent depressurization of the Hydrocracker 2nd Stage Reactor. SO ₂ emitted over 1,000 ppm limit estimated at 130 pounds. Penalty paid \$5,000.

3827	8/15/09	2/16/10	The electric motor driving the Delayed Coker Wet Gas Compressor had a catastrophic failure shutting down the compressor for eleven days. Sour gas normally captured by the compressor was rerouted to the low pressure flare gas recovery system resulting in flaring exceeding the SO ₂ limit of 1,000 ppm, corrected to 7% oxygen for 75 hours. The event resulted in 163 tons of excess SO ₂ emissions. No penalty assessed because event considered unavoidable.
3878	6/6/10	1/7/11	SO ₂ emissions from the low pressure flare exceeded 1,000 ppm corrected to 7% oxygen, hourly limit. The excess emissions were caused by the combustion of vacuum tail gas during maintenance of the amine contact condenser. Total excess emissions from the event were estimated to be 175 lb SO ₂ . Penalty paid \$10,000.
3902	Multiple	5/2/11	Failure to submit test plans and summary sheet with the final test report for two heaters tested in 2010, and failure to submit a test plan for one heater tested in 2010, and one heater tested in 2009. Penalty paid \$12,000.
3951	11/19/10	2/24/12	Refinery wide steam interruption caused by a series of boiler trips attributed to cold weather and subsequent equipment shutdowns and depressurization of vessels to the flare gas recovery system resulted in intermittent excess emissions from many sources including from flares, heaters and boilers. Penalty paid \$15,000.

1.4 Periodic Reports

BP Cherry Point 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.

Monthly Reports: Monthly emissions reports are submitted to the NWCAA within 30 days following the end of each calendar month. Similar to all recordkeeping, the supporting data must be maintained for least five years from its date of generation. Monthly emission reports for the refinery include a wide range of data collected during the month. A large part of the monthly report includes 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.

Table 1-2: CEMS at the Cherry Point Refinery

CEM Location	Required CEMS Parameters
South Vacuum Heater	NOx , O ₂
North Vacuum Heater	O ₂
#1 DHDS Charge Heater	NOx , O ₂
#1 DHDS Stabilizer Reboiler	NOx , O ₂
Hydrocracker 1 st Stage Reactor Heater	NOx , O ₂
Hydrocracker 1st Stage Fractionator Reboiler	NOx , O ₂
#1 & #2 Calciners	SO ₂ , NOx , O ₂
#3 Calciner	SO ₂ , NOx , O ₂
#4 Boiler	NOx , O ₂
#5, 6 & 7 Boilers	NOx , CO, O ₂
#2 Hydrogen Plant SMR Furnace	NOx , CO, SO ₂ , CO ₂ , O ₂
Main Refinery Fuel Gas	H ₂ S
Coker Fuel Gas	H ₂ S
Vacuum Tail Gas (Crude and Vacuum Unit)	H ₂ S
Sulfur Recovery Complex, Incinerator	SO ₂ , O ₂
Sulfur Recovery Complex, #2 TGU	SO ₂ , O ₂

Another, significant element of monthly reports is the disclosure of deviations from required monitoring and deviations caused from exceeding an enforceable emission limit. The monthly report also includes information on the H₂S content of refinery fuels gas and provides an indication of the performance characteristics of the amine scrubbing systems located throughout the refinery. There are many other data elements that are reported in a monthly basis as required by permits, orders and regulations.

Quarterly and Semiannual Reports:

The refinery is required to submit the following quarterly reports:

- CEM quality assurance reports which document drift, out of control periods, and the results of relative accuracy test audits (RATA) and cylinder gas audits (CGA).
- 40 CFR 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The Subpart Db report includes NOx emission rates and CEM performance data for the #4, 5, 6 & 7 Boilers.
- 40 CFR 61 Subpart FF - National Emission Standard for Benzene Waste Operations requires quarterly reports certifying that the company met all applicable Subpart FF requirements. These include, but are not limited to; instrument monitoring for activated carbon bed breakthrough and visual inspections of oily wastewater seals.

The refinery is required to submit the following semiannual report:

- 40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries requires semiannual reports. This report includes any compliance exceptions to the requirement of the rule including, but are not limited to: delay of repair of storage tanks, failure of any pilot light on a flare, and leak detection and repair monitoring

summaries. The initial Subpart CC Notification of Compliance Status report was submitted by the refinery on January 14, 1999. The first semiannual report was due on September 15, 1999, eight months after Notification of Compliance Status report and included information on the first six month period running January 15, 1999 through July 14, 1999. Current semiannual reports remain on this schedule with January 15 through July 14 reporting periods due on September 15 of each year, and July 15 through January 14 reporting periods due on March 15 of each year, i.e., 60 days after the end of the reporting period.

1.5 Annual Emission Inventories

Each year the refinery is required to submit an air pollution emissions inventory upon request of the NWCAA. This report includes criteria air pollutants, hazardous air pollutants (HAP), and from 2010 forward greenhouse gas (GHG) emissions. Emissions from the Cherry Point Refinery are included in the NWCAA emissions inventory report that the agency published each year that includes emissions summaries for all of the large industrial facilities located within Whatcom, Skagit and Island counties.

The Table 1-3 summarizes the last five years of available emissions data for the Cherry Point Refinery. In general, emission rates at the refinery vary from year to year depending on the slate of crude oils used as a feedstock, the types and amounts products produced, modifications to process equipment and/or emission control devices, and to some extent improvements in the methods used to calculate emissions.

Table 1-3: Annual Emissions from the Cherry Point Refinery

Pollutant	Calendar Years Emissions (tons)				
	2007	2008	2009	2010	2011
PM ₁₀	148	139	159	155	81
SO ₂	1,387	1,764	2,134	1,283	1,028
NO _x	2,074	2,237	2,228	2,223	2,051
VOC	388	380	466	486	454
CO	690	699	746	688	677
HAP	116.2	115.5	127.7	132.5	143.6
GHG (CO ₂ e)	n/a	n/a	n/a	2,767,634	2,678,687

2 GENERAL REGULATORY REQUIREMENTS

This portion of the Statement of Basis discusses a wide range of topics including federal regulations (i. e., NSPS and NESHAP) that are found throughout the permit, to items such as the BP 2001 Consent Decree that is not found in the permit because its conditions are not considered applicable requirements under the Title V program.

2.1 New Source Performance Standards (NSPS)

The refinery owns and operates specific affected equipment regulated under the following NSPS Subparts. When a NSPS applies to a facility, the General Provisions of 40 CFR 60 Subpart A also apply. Some of the requirements of Subpart A are included in the AOP, and some are not. Generally, if a Subpart A requirement is applicable when triggered by a particular action it is found in Section 3 of the AOP. Similarly, if a part of Subpart A does not have a specific requirement 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 not in the AOP.

Generally, NSPS regulations are directly applicable based on the date an affected unit was constructed, reconstructed or modified. The following is a summary of NSPS regulations that are applicability at the Cherry Point Refinery.

1. 40 CFR 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Based on their heat input capacity size being greater than 100 MMBtu/hour and date of construction being after June 19, 1984, all boilers at the Cherry Point Refinery (#4, 5, 6 & 7) are affected units under Subpart Db and subject to the NO_x and SO₂ requirements of the rule. To demonstrate compliance with the 0.20 lb/MMBtu limit each boiler is equipped with CEMS to continuously monitor NO_x emissions. Subpart Db requires that the NO_x CEMS be calibrated at 500 ppm, however, because of relatively low BACT limits for NO_x applicable to each boiler established under OACs, each CEM is operated at a range below 500 ppm. Specifically, the CEM for the #4 Boiler has a NO_x ppm range of 0-250 ppm, while #5, 6 & 7 Boilers have a 0-100 ppm. As a result, it is impractical to calibrate the CEMS at the Subpart Db specified 500 ppm value. Instead, they are calibrated within the CEMS's monitoring range. This is a minor change to the refineries compliance method and it is a change that EPA has allowed in writing for similar facilities. For example, EPA allowed Air Products and Chemicals, Incorporated of Kentucky to use a calibration value below 500 ppm for a Subpart Db applicable unit in their February 17, 2000, letter to the Kentucky Division of Air Quality (EPA ADI 0000029) "provided that the span value is set high enough to ensure that all emissions from the unit can be quantified". With regard to the NO_x CEMS for #4, 5, 6 & 7 Boilers, the CEM may be operated and calibrated below 500 ppm as long as each boiler is operated within the range of its CEM.

40 CFR 60 Subpart Db includes a provision requiring that each boiler meet the SO₂ requirement of 40 CFR 60 Subpart J of 162 ppm H₂S, three hour average for fuel gas combusted in the boiler. Compliance with this limit is demonstrated using a CEMS for H₂S.

Subpart Db applies to each of the boilers at the refinery, however, because these boilers are required to combust only gaseous fuel, they are not subject to the particulate standards of Subpart Db.

This subpart includes a 100 MMBtu/hour heat input applicability threshold. As a result the supplemental fuel firing for steam generation at the #1 & #2 Calciners (60 MMBtu/hour each) and the #3 Calciner (86 MMBtu/hour) are exempt from Subpart Db applicability.

2. 40 CFR 60 Subpart J and Subpart Ja - Standards of Performance for Petroleum Refineries

All fuel gasses combusted in the refinery are required to meet the New Source Performance Standards (NSPS) under 40 CFR 60 Subpart J or Subpart Ja. Subpart J applies to combustion devices that were constructed, reconstructed or modified after June 11, 1973, and on or before May 14, 2007. Subpart Ja applies to combustion devices that were constructed, reconstructed or modified after May 14, 2007. In addition, NWCAA Agreed Compliance Order (ACO) 05 requires that heaters and boilers at the refinery meet the fuel gas sulfur limits of Subpart J for heaters and boilers that were in place on June 18, 2001, the lodging date of the BP 2001 Consent Decree.

The table below summarizes regulatory applicability for each combustion device at the refinery.

Table 2-1 : Subpart J and Ja Regulatory Applicability for Combustion Devices

	Subpart J	Subpart Ja	ACO 05
Crude Heater			X
South Vacuum Heater			X
North Vacuum Heater	X		X
#1 Reformer Heater			X
#2 Reformer Heater	X		X
Naphtha HDS Charge Heater			X
Naphtha HDS Stripper Reboiler			X
Hydrocracker 1st Stage Reactor Heater			X
Hydrocracker 2nd Stage Reactor Heater			X
Hydrocracker 1st Stage Fractionator Reboiler			X
Hydrocracker 2nd Stage Fractionator Reboiler			X
North Coker Charge Heater			X
South Coker Charge Heater			X
#1 Diesel HDS Charge Heater			X
#1 Diesel HDS Stabilizer Reboiler			X
#2 Diesel HDS Charge Heater	X		
#3 Diesel HDS Charge Heater		X	
Isomerization IHT Heater	X		
#1 Hydrogen Plant, North Reforming Furnace			X
#1 Hydrogen Plant, South Reforming Furnace			X
#2 Hydrogen Plant SMR Furnace		X	
#1 & #2 Calciners (supplemental fuel)	X		X
#3 Calciner (supplemental fuel)	X		X
#4 Boiler	X		X
#5 Boiler	X		
#6 Boiler	X	X	
#7 Boiler	X	X	
Truck Loading Rack Vapor Combustor	X		
Sulfur Recovery Complex Incinerator (supplemental fuel)	X		
High and Low Pressure Flares		X	

Subpart J requires that the concentration of hydrogen sulfide (H₂S) in refinery fuel gas burned in affected combustion devices 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 a 293° Kelvin and 101.3

kilopascals. Because H₂S is continuously monitored as ppmvd, the Subpart J standard of 230 mg/dscm has been converted to ppm and the ppm limit included in applicable AOP term.

$$\frac{230 \text{ mg H}_2\text{S}}{\text{dscm air}} \times \frac{1 \text{ g H}_2\text{S}}{1,000 \text{ mg H}_2\text{S}} \times \frac{1 \text{ mol H}_2\text{S}}{34.082 \text{ g H}_2\text{S}} \times \frac{24.056 \text{ L H}_2\text{S}}{\text{mol H}_2\text{S (ideal gas law)}} \times \frac{1 \text{ dscm H}_2\text{S}}{1,000 \text{ L H}_2\text{S}}$$

$$= \frac{162 \text{ dscm H}_2\text{S}}{1,000,000 \text{ dscm air}} = 162 \text{ ppmdv H}_2\text{S in air}$$

40 CFR 60 Subpart Ja a same refinery fuel gas H₂S limit of 162 ppmv as a 3-hour average, and therefore does not need to be converted to ppmv for the AOP term. Subpart Ja also includes a 60 ppmv limit for H₂S as a 365 successive calendar day rolling average for combustion devices, excluding flares. The Subpart Ja limits are not listed as dry because the fuel gas is inherently a dry gas. As such, the Subpart J and Subpart Ja 162 ppmv limits are essentially equivalent.

The refinery operates a Sulfur Recovery Complex where applicable 40 CFR 60 Subpart J requirements limit SO₂ emissions from the Incinerator and #2 TGU stacks to 250 ppmvd at 0% oxygen. Compliance with this standard is demonstrated using a continuous emissions monitoring system (CEMS) for SO₂ as required by the rule.

On December 22, 2008, the federal register published a notice of 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. The permit lists the publication dates for Subparts Ja as 6/24/08 as amended 9/12/12 because the fully revised version of the rule has not yet been published.

The low and high pressure flares are subject to 40 CFR 60 Subpart Ja due to 2009 maintenance turnaround tie-ins and have until November 13, 2015 to comply with the provisions for flares. Flares are required to meet the 162 ppm H₂S limit for gasses that are being flared unless the gasses are a result of leaking relief valves or from an emergency malfunction event or startup and shutdowns. The rule also requires that the refinery: 1) developed and implement a flare management plan, 2) conduct a 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, or contains sulfur that, upon combustion, will emit more than 500 pounds of SO₂ in a 24-hour period; and 3) optimize management of the fuel gas by limiting the short-term concentration of H₂S to 162 ppmv during normal operating conditions.

The #2 Hydrogen Plant will be equipped with a new elevated flare that will combust gas streams that are inherently low in sulfur content. Under Subpart Ja, the flare may not burn gas that contains H₂S in excess of 162 ppmv determined on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit. (Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.) Subpart Ja exempts gasses that are inherently low in sulfur from the monitoring requirements of the rule. Specifically, 40 CFR 60.107a(a)(3)(iii) exempts flared gas streams produced in hydrogen plants from H₂S and total reduced sulfur monitoring requirements of Subpart Ja because the process is intolerant to sulfur contamination. On November 16, 2012, the NWCAA received a notice from the refinery describing this exemption from monitoring.

Vapors recovered at the Marine Terminal during loading operations are not considered a fuel gas regulated under Subpart J. This is because the definition of fuel gas in 60.101 states, "Fuel gas

does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units or marine tank vessel loading operations.”

3. 40 CFR 60 Subparts K, Ka and Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels

The following New Source Performance Standards apply to tanks (i.e., vessels) storing organic liquids at the refinery depending on the date the tank was constructed, reconstructed or modified.

- 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
- 40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

There are no tanks at the refinery that were constructed, reconstructed or modified during the applicability dates of 40 CFR 60 Subpart Ka.

- 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.

Refer to “Storage Tanks and Vessels” under Section 3 for a description of the storage tanks at the refinery and their applicable requirements.

4. 40 CFR 60 Subparts GGG and GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

The refinery has constructed, modified, or reconstructed various process units, triggering the applicability either 40 CFR 60 Subpart GGG, or the more recent Subpart GGGa. Subpart GGG applies to process units with equipment components in VOC service that have been constructed, reconstructed, or modified between January 4, 1983, and November 7, 2006. Whereas Subpart GGGa applies to process units with equipment components in VOC service that have been constructed, reconstructed, or modified on or after November 7, 2006. The rules provide an applicability exception. Those process units 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. In general, these LDAR standards are considered work practice standards that require that the refinery use an instrument to find leaking components such as valves and pumps, and to repair them in a timely manner.

Some process units are subject to the 40 CFR 63 Subpart CC because they have Group 1 components that are in hazardous air pollutant (HAP) service. The overlap provisions of 63.640(p)(1) state that, “equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart”. Whereas, 63.640(p)(2) states that, “equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa”.

Subparts VV and VVa specifies standards specifies 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.

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 is 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 shutdown for maintenance.

The BP 2001 Consent Decree requires the refinery to implement an "enhanced" LDAR program that is more stringent than the requirements of Subpart VV. In addition, the NWCAA has required some enhanced LDAR programs under BACT determinations that are required under specific OAC conditions. See Section 3 regarding leak detection and repair programs implemented throughout the refinery and a description of their various applicability drivers.

5. 40 CFR 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

The refinery has added or modified individual drain systems at a number of process units after May 4, 1987, thereby triggering applicability of NSPS Subpart QQQ at those affected units. The table below presents a list of process units/areas that have Subpart QQQ applicability and lists OACs associated with particular projects.

Table 2-2 Individual Drain Systems and NSPS Subpart QQQ Applicability

Process Unit	NSPS QQQ Constructed/ Modified after 5/4/87	Process Unit	NSPS QQQ Constructed/ Modified after 5/4/87
Crude/Vacuum	OAC 640a	Sour Water Unit	Yes
#1 Reformer	OAC 562d	Wastewater Treatment Plant	Yes
Naphtha HDS		Tank Farm	OAC 620, OAC 897
#2 Reformer		Chemical Treater	Yes
Hydrocracker	Yes	Truck Rack	OAC 527d
Delayed Coker	OAC 689b	Marine Terminal	
#1 Diesel HDS		LPG/LEU Loading	
#2 Diesel HDS	OAC 892b	LPG Unit	Constructed 1987
#1 Hydrogen Plant		Isomerization Unit	OAC 814b
#2 Hydrogen Plant	OAC 1064a	NE Rail Facility	OAC 1142, Constructed 2013
#1 & #2 Calciners	OAC 689b	Utility Boilers	OAC 1001c
#3 Calciner	Yes	Flare Gas Recovery & Flares	
Light Ends Unit	Yes	Sulfur Recovery Complex	OAC 1043

Under the Refinery MACT overlap provisions of 40 CFR 63 Subpart CC §63.640(o), any Group 1 wastewater stream subject to 40 CFR 60 Subpart QQQ is required to comply only with the requirements the NESHAP for Benzene Waste Operations under 40 CFR 61 Subpart FF standards. Under 40 CFR 63 Subpart CC, a "Group 1 wastewater stream" is defined as:

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

Under 40 CFR 63 Subpart CC, a "Group 2 wastewater stream" is defined as:

"a wastewater stream that does not meet the definition of Group 1 wastewater stream."

In a letter from BP Cherry Point Refinery to the NWCAA dated June 23, 2009, BP states that they are re-designating all waste water streams subject to NSPS 40 CFR 60 Subpart QQQ and also defined as Group 2 wastewater streams under 40 CFR 63 Subpart CC to "Group 1 wastewater streams". In doing so BP is required only to control and treat those wastewater streams under the standards of 40 CFR 61 Subpart FF as required by §63.640(o). Consequently, there are no 40 CFR 60 Subpart QQQ requirements listed in the AOP. Instead, the previously Subpart QQQ wastewater streams are under the refinery-wide 40 CFR 61 Subpart FF program. The AOP terms for Subpart FF are listed in Section 5 of the permit under "Oily Wastewater Collection, Storage and Treatment".

Because Subpart QQQ has more specific requirements (§60.692-2) for individual drain systems than Subpart FF, AOP Term 5.16.1 has been gap-filled as follows to ensure that there has been no backsliding in stringency:

Directly Enforceable

Each active service drain shall be inspected monthly for indication of low water levels or other conditions that would reduce the effectiveness of the water seal control. Whenever low water levels are identified water shall be added or first efforts to repair shall be made as soon as practical but no later than 24 hours after detection.

Each inactive service drain shall be inspected weekly for indication of low water levels or other conditions that would reduce the effectiveness of the water seal controls or problems that could result in emissions to the atmosphere.

6. 40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

All stationary internal combustion engines at the refinery are categorized as compression ignitions (CI) engines under 40 CFR 60 Subpart IIII. They are considered compression ignition because they burn diesel fuel and use the heat of compression for ignition. Each engine is subject 40 CFR 60 Subpart IIII because construction commenced after July 11, 2005. The emergency generator engines were manufactured after April 1, 2006, and the fire pump engine was manufactured after July, 2006.

In summary, 40 CFR 60 Subpart IIII requires that the engines burn only ultralow sulfur diesel with a sulfur content equal to or less than 15 ppmw, and that the engine has a permanent label documenting that it meets the emission limits applicable for its model year and power rating.

Each stationary internal combustion engine at the refinery is also subject to 40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants: Reciprocating Internal Combustion Engines.

2.2 National Emission Standards for Hazardous Air Pollutants

(NESHAP/MACT)

BP Cherry Point owns and operates specific affected equipment regulated under the following NESHAP/MACT Subparts. When a NESHAP applies to a facility, the General Provisions of 40 CFR 61 or 63 Subpart A also apply. Some of the requirements of Subpart A are included in the AOP and some are not. Generally, if a Subpart A requirement is applicable when triggered by a particular action it is found in Section 3 of the AOP. Conversely, if a part of Subpart A does not have specific requirement 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 not in the AOP.

1. 40 CFR 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene

The #1 Reformer includes a light reformate splitter tower (LRF) that has the capacity to concentrate benzene above the 10% by weight applicability threshold of 40 CFR 61 Subpart J. However, 40 CFR 63 Subpart CC includes the following overlap provision.

(p) Overlap of subpart CC with other regulations for equipment leaks.

(1) After the compliance dates specified in paragraph (h) of this section, equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart.

Because 40 CFR 61 Subpart J was promulgated before September 4, 2007, and Subpart CC has applicability trigger of 4% by weight for benzene as a HAP that is more stringent than Subpart J, this overlaps provision applies to all equipment in benzene service as defined in Subpart J. As a result the refinery only comply with equipment leak provisions Subpart CC, and 40 CFR 61 Subpart J is not cited in the AOP.

2. 40 CFR 61 Subpart FF - National Emission Standard for Benzene Waste Operations

In 1991, the refinery was required to come into compliance with 40 CFR 61 Subpart FF. The purpose of this regulation was to reduce the amount of benzene emissions to the atmosphere from wastewater operations. Benzene is a regulated HAP under the NESHAP regulations. The refinery's total annual benzene (TAB) quantity is calculated each year, and is consistently above the 10 Mg/yr threshold for Subpart FF applicability. The TAB does not represent the level of benzene emissions to the atmosphere from waste operations, but rather the total amount of benzene that enters the waste water collection system.

The refinery complies with 40 CFR 61 Subpart FF through the various control requirements of the rule. The standard allows the refinery to exempt waste streams by demonstrating that initially, and at least once a year thereafter that either:

The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gpm) or an annual wastewater quantity of less than 11 tons/year; or

The total annual benzene quantity in all waste streams chosen for exemption does not exceed 2.0 Mg/yr (2.2 tons/year) as determined by 40 CFR 61.355(j); and

The streams selected for exemption, includes process turnaround waste, and that that exempt waste quality is determined for the calendar year in which the waste has generated.

There are several options for the control of emissions and treatment of the wastewater. The refinery has selected to use a closed vent system (§61.349), covered oil/water separators (§61.347), carbon adsorption canisters (§61.349), and an enhanced biodegradation unit for the treatment of the process wastewater.

3. 40 CFR 61 Subpart BB – National Emission Standards for Hazardous Air Pollutants: Benzene Operations

40 CFR 63 Subpart BB applies to benzene distribution activities at the refinery. The refinery has the potential to trigger the control standards of Subpart BB, especially, during an event where the Isomerization Unit is shutdown for an extended period and the refinery is in a position to ship out the benzene rich Isomerization unit feedstock in lieu of processing. The refinery does not anticipate a scenario where an extended Isomerization unit shutdown is likely. Therefore, the 40 CFR 63 Subpart BB provisions applicable to the refinery are recordkeeping only, and found in Section 5 of the AOP under Organic Liquids Distribution.

4. 40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

The first seven sections of 40 CFR 63 Subpart CC (commonly referred to as Refinery MACT I) address equipment applicability. The process units at the refinery are subject to 40 CFR 63 Subpart CC if they have equipment containing or contacting one or more of the hazardous air pollutants listed in the NESHAP. The subject units include:

- Miscellaneous process vents
- Storage vessels
- Wastewater streams and treatment operations
- Marine tank vessel loading
- Equipment leaks from petroleum refining process units

There are some important equipment exemptions listed in the Refinery MACT, including catalytic cracking unit and catalytic reformer catalyst regeneration unit vents, as well as sulfur plant vents and emission points routed to a fuel gas system. Other than the emission points routed to a fuel gas system, this equipment was included in Part 63 Subpart UUU, which is commonly referred to as Phase II MACT.

The 40 CFR 63 Subpart CC requires that HAP emissions be controlled from various emission points with the refinery. Some of these emissions points may also be subject to other existing regulations including NSPS and other NESHAPs. It was not the intent of the 40 CFR 63 Subpart CC to place an additional burden on the refinery, but rather to allow the source to comply with only the most stringent regulation which will demonstrate compliance with all applicable regulations.

For miscellaneous process vents 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 40 CFR 63 Subpart CC. Atmospheric vents at the hydrogen plants are exempt from 40 CFR 63 Subpart CC requirements under the definition of a miscellaneous process vents at §63.641(14).

For storage vessels, there is overlap of the 40 CFR 63 Subpart CC with 40 CFR 60 Subpart K and Subpart Kb. The 40 CFR 63 Subpart CC is applicable for all Group 1 storage vessels not already governed by 40 CFR 60 Subpart Kb. For Group 2 storage vessels, if the control requirements of 40 CFR 60 Subpart K or Kb do not apply, the vessel is subject to 40 CFR 63 Subpart CC. All vessels not subject to Subparts K and Kb are subject to 40 CFR 63 Subpart CC. A Group 1 or Group 2 storage vessel that is subject to 40 CFR 60 Subpart Kb, is required to comply only with the requirements in 40 CFR 60 Subpart Kb.

There are several wastewater stream regulations that overlap or are cross referenced in 40 CFR 63 Subpart CC. These are 40 CFR 60 Subpart QQQ, 40 CFR 61 Subpart FF, and 40 CFR 63 Subpart G. New and existing sources in compliance with 40 CFR 61 Subpart FF are considered to be in compliance with the standards of 40 CFR 63 Subpart CC. Subpart CC standards apply only to

Group 1 streams that are subject to 40 CFR 60 Subpart QQQ. Group 2 streams in which Subpart QQQ applies are still subject to Subpart QQQ.

Existing gasoline storage racks are governed by 40 CFR 63 Subpart R, which is referenced in 40 CFR 63 Subpart CC. New sources are subject to 40 CFR 60 Subpart XX but are only required to comply with the requirements of the MACT standard.

Marine Vessel loading operations are subject 40 CFR 63 Subpart CC, which references the control requirements of 40 CFR 63 Subpart Y - National Emission Standard for Marine Tank Vessel Loading Operations.

Equipment leaks standards in 40 CFR 63 Subpart CC cross-reference 40 CFR 60 Subpart VV and the modified 40 CFR 63 Subpart H. The refinery has selected to use the standards and monitoring, recordkeeping, and reporting requirements (MR&Rs) listed in 40 CFR 60 Subpart VV to demonstrate compliance for their existing sources. However, new sources at the refinery have to comply with the standards of 40 CFR 60 VVa when NSPS Subpart GGGa is triggered. Compressors in hydrogen service are considered exempt from the monitoring and recordkeeping requirements.

On 1/16/09 the EPA administrator signed revisions to 40 CFR 63 Subpart CC that addressed 1) technology-based requirements for heat exchangers and 2) risk-based requirements for all 40 CFR 63 Subpart CC regulated items in response to a consent order schedule. The signed rule was never published in the Federal Register (FR) and therefore, never had an effective date. On 10/28/09 EPA published a final rule [74 FR 207 pp 55669-55692] that codified into 40 CFR Part 63 Subpart CC the same technology-based requirements for heat exchangers that were in the 1/16/09 signed rule, thereby making those requirements effective with a compliance date of 10/29/2012, 3 years from final publication. On 6/30/10 EPA published a final rule [75 FR 125 pp 37730-37732] that made administrative corrections to the final rule that was published 10/28/09. The publication date cited in the AOP is therefore 6/30/10, however, the compliance date is considered three years after the initial final rule publication date of 10/28/09, or 10/29/2012.

Parallel to the finalization of the technology-based heat exchanger regulations, and also on 10/28/09, EPA published a proposed rule [74 FR 207 pp 55505-55506] to withdraw the residual risk items that were in the 1/16/09 signed rule. This FR action was required because the Federal Clean Air Act holds an EPA administrator-signed rule as a "significant action" that warrants FR notice on any further action. On 7/18/11 EPA published the final rule [76 FR 137 pp 42052-42055] withdrawing the residual risk items that were in the 1/16/09 signed rule. These Federal Register notices had no effect on the 40 CFR 63 Subpart CC as promulgated to date.

5. 40 CFR 63 Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

40 CFR 63 Subpart UUU (commonly referred to as Refinery MACT II) which became effective on April 11, 2005 contains continuing applicable requirements for the refinery's catalytic reforming units (during depressuring operations and catalyst regeneration) and sulfur recovery complex. The refinery was required to provide an operation, maintenance and monitoring (OM&M) plan for each reformer and the Sulfur Recovery Complex and abide by the plans at all times during operation of these units.

Organic HAP emissions during depressuring of the reformers are to be controlled by purging the unit to a combustion device that meets a destruction efficiency of 98%. In addition, inorganic HAP emissions during coke burn off and catalyst regeneration must be reduced by 98%.

Subpart UUU requires that emissions at the Sulfur Recovery Complex meet the 40 CFR 60 Subpart J requirement of 250 ppm SO₂ at 0% oxygen, 12-hour rolling limit.

6. 40 CFR 63 Subpart Y - National Emission Standards for Marine Tank Vessel Loading Operations

The Marine Terminal at the refinery is subject to 40 CFR 63 Subpart CC. However, Subpart CC simply references 40 CFR 63 Subpart Y for the applicable requirements. Under Subpart Y vapors displaced during marine loading operations must be controlled by a vapor collection system. Subpart Y specifies that the marine tank vessel must be compatible with the terminal's vapor collection system and must be vapor tight.

7. 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Boilers and Process Heaters

At the time of the AOP permit renewal, 40 CFR 63 Subpart DDDDD, commonly referred to as the Major Source Boiler MACT, was promulgated as a final rule on March 21, 2011. However, on February 7, 2012, EPA issued a "No Action Assurance" letter stating that the rule was under reconsideration and that the agency would not pursue enforcement action on initial notification requirements under the rule. The letter does not relieve affected sources from compliance other requirements of the rule.

On February 1, 2012, the NWCAA received an initial notice from the refinery as required under 40 CFR 63 Subpart DDDDD stating that all of the process heaters and boilers currently operating at the refinery are considered existing sources under the rule. The #2 Hydrogen Plant Furnace and #3 Diesel DHS Charge Heater that are currently under construction are considered new units under the rule because their construction commenced after June 4, 2010. Based on information contain in this submittal, all of the process heaters and boilers at the Cherry Point Refinery are considered affected units under the 40 CFR 63 Subpart DDDDD, all have a heat input capacity equal to or greater than 10 MMBtu/hour, and all are considered to be in the "Gas 1" category (natural gas or refinery fuel gas). The initial notification did not list any of the calciners as affected facilities under Subpart DDDDD. The #1, #2 and #3 Calciners can burn refinery fuel gas as supplemental fuel to generate steam when calcining operations are curtailed. However, this does not trigger Subpart DDDDD applicability because the primary purpose of the calciners is not to generate steam.

On January 31, 2013 EPA issued a revised final rule. Affected sources under the subpart continue to be boilers and process heaters. The same equipment at BP is covered by the January 31, 2013 version of the rule as was covered by the earlier version (the calciners continue to be exempt). All of the subject units are greater than 10 MMBtu/hr in size. Units are considered to be "new" if they commenced construction after June 4, 2010. The only "new" units at BP are the #3 DHDS and the #2 Hydrogen Plant SMR furnace. All subject units are classified as "gas 1" units. As they are configured and operated, none of the subject units at BP are capable of running on liquid or solid fuels. OAC 1054 originally approved the use of liquid fuel at the Crude Unit, South Vacuum Charge Heater, North Coker Charge Heater and South Coker Charge Heater. The language from this OAC has been retained as a historical. However, the units were not constructed with this capability and the OAC approval to commence construct of liquid fuel handling and burning systems has long since expired. Hence, these units are considered "gas 1" units under 40 CFR 63 Subpart DDDDD.

Subpart DDDDD does not require any pollutant specific emission limits for existing or new heaters and boilers in the "Gas 1" category. Instead, the rule requires work practice standards that include "tune-ups" as defined in §63.7540(a)(10) and a one-time energy assessment performed by a qualified energy assessor. (The energy assessment is required only for existing units.) The refinery is required to maintain records of the amount of fuel used in each heater or boiler, the dates and hours that it operated, startup and shutdown events, and the date and result of each tune-up and energy assessment performed under the rule.

For Gas 1 units, tune-ups are required once every 5 years for units with oxygen trim systems, and annually for units without oxygen trim systems. At the time that Modification 1 to AOP 015R1M1 was written, BP was still compiling a list of which units have oxygen trim systems. Until BP identifies and documents a unit as having an oxygen trim system, BP will perform the required tune-ups annually. A list of units with oxygen trim systems may be added to the SOB at the next permit modification or renewal.

8. 40 CFR 63 Subpart EEEE – National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

40 CFR 63 Subpart EEEE applies to non-gasoline organic liquid distribution activities at the refinery that handle HAPs over thresholds specified in the rule. 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 applicability. Because 40 CFR 63 Subpart CC requires Refinery MACT controls at the truck rack and marine terminal, Subpart EEEE does not apply to these specific activities. However, railcar loading and/or other organic liquids distribution that is not addressed by Subpart CC has the potential to trigger the control standards of Subpart EEEE, especially, during an event where the Isomerization Unit is shutdown for an extended period and the refinery is in a position to ship out the benzene rich Isomerization unit feedstock in lieu of processing. The refinery does not anticipate a scenario where an extended Isomerization unit shutdown is likely. Therefore, the 40 CFR 63 Subpart EEEE provisions applicable to the refinery are recordkeeping only, and found in Section 5 of the AOP under Organic Liquids Distribution.

9. 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants: Reciprocating Internal Combustion Engines

All stationary internal combustion engines at the refinery are categorized as new compression ignitions (CI) engines under 40 CFR 63 Subpart ZZZZ. They are considered “new” and not “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. All stationary CI engines at the refinery are subject to Subpart ZZZZ, however, Subpart ZZZZ does not specify any requirements for these engines; except for initial notification for engines greater than 500 hp.

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.

For new CI engines that are in emergency use and greater 500 hp;

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

The NWCAA received the initial notification for the 1,356 hp emergency generator located at the Fresh Water Pond area on March 12, 2012. This one-time only requirement has been met and is not included in the AOP.

10. 40 CFR 63 Subpart GGGGG – National Emission Standards for Hazardous Air Pollutants: Site Remediation

40 CFR 63 Subpart GGGGG applies to site remediation activities at the refinery. Because the total HAP quantity in remediation materials for the year is less than 1 Mg, the refinery is not subject to the requirements of this standard. However, the refinery is obligated to maintain written documentation to support this determination. This recordkeeping requirement is found in Section 4 of the AOP because it is a generally applicable requirement that applies refinery-wide.

11. Compliance Assurance Monitoring

40 CFR 64 - Compliance Assurance Monitoring (CAM rule) requires owners and operators to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not the CAM applicable units meet established emission standards. If owners and operators of these facilities find that their control equipment is not working properly, the CAM rule requires that action be taken to correct any malfunctions and to report such instances to the appropriate enforcement agency. Additionally, the CAM rule provides some enforcement tools that will help agencies require facilities to respond appropriately to the monitoring results and improve pollution control operations.

The CAM rule applies to each Pollutant Specific Emissions Unit (PSEU) located at major CAA Title V source that meets of the following criteria:

- Is subject to an emission limitation or standard, and
- Uses a control device to achieve compliance, and
- Has potential pre-controlled emissions exceeding a major source threshold.

The Cherry Point Refinery includes the following four PSEUs.

Table 2-3 CAM Pollutant Specific Emissions Units

PSEU	Pollutant and Control Device	Emission Limit(s)
#1 and #2 Calciner Hearth (Stack #1)	PM ₁₀ Controlled by Wet Electrostatic Precipitator (WESP)	<ul style="list-style-type: none"> • 34 tons, consecutive 12-month rolling (OAC 689b)
	H ₂ SO ₄ Controlled by WESP	<ul style="list-style-type: none"> • 15 lb/hour (OAC 660a) • 62 mg/dscf @ 7% O₂ calendar day ave. (OAC 689b) • 39 tons, consecutive 12-month rolling (OAC 689b)
#3 Calciner Hearth (Stack #2)	PM ₁₀ Controlled by Wet Electrostatic Precipitator (WESP)	<ul style="list-style-type: none"> • 0.01 gr/dscf @ 7% O₂, 60-minute ave. (OAC 985a, PSD-89-2) • 26 tons, consecutive 12-month rolling (PSD-89-2)

PSEU	Pollutant and Control Device	Emission Limit(s)
	H ₂ SO ₄ Controlled by WESP	<ul style="list-style-type: none"> • 18.3 lb/hour, 60-minute rolling average (OAC 985a) • 50 mg/dscm, 60-minute rolling average (OAC 985a)
North Coker Charge Heater - and - South Coker Charge Heater	NO _x Controlled by Flue Gas Recirculation (FGR)	<ul style="list-style-type: none"> • 15.2 lb/hour (OAC 689b)

For these PSEUs, the CAM rule requires that air operating permit include;

An approved monitoring approach, including the indicators to be monitored, and performance requirements established to satisfy 40 CFR 64.3 (b) or (d), as applicable;

- The means by which the owner or operator will define exceedances or excursions;
- The duty to conduct monitoring;
- If appropriate, minimum data availability and averaging period requirements; and
- Milestones for testing, installation, or final verification.

Section 5 of the air operating permit includes the appropriate monitoring parameters and methods to determine compliance as submitted by BP in their associated CAM plans for these PSEUs.

2.3 Leak Detection and Repair (LDAR)

Fugitive VOC and HAP emissions occur throughout the refinery from leaking process equipment. These components include pumps, valves and compressors, flanges, open-ended lines and safety vents to the atmosphere. Process units at the refinery are periodically monitored for leaks and when leaks are identified they are required to be repaired within the time deadline in the applicable requirement. This work practice standard is referred to as a leak detection and repair (LDAR) program.

For any particular process unit, there may be one or more LDAR requirements driving the program depending on the date of construction or modification of any particular process unit.

- NWCAA Section 580.8 requires a LDAR program conducted in accordance with 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.
- 40 CFR 63 Subpart CC requires a LDAR program conducted in accordance with 40 CFR 60 Subpart VV for components in HAP service.
- 40 CFR 60 Subpart GGG requires a LDAR program conducted in accordance with 40 CFR 60 Subpart VV in the entire process unit for components in VOC service. Applicability is triggered when construction, reconstruction, or modification commences after January 4, 1983, and on or before November 7, 2006.
- 40 CFR 60 Subpart GGGa requires a LDAR program conducted in accordance with 40 CFR 60 Subpart VVa in the entire process unit for components in VOC service. Applicability is triggered when construction, reconstruction, or modification commences after November 7, 2006.

- Orders of Approval to Construct (OAC) issued under minor new source review (NSR) may require an enhanced LDAR program as a condition of the order under BACT.

If a process unit has any components in Group 1 HAP service as defined 40 CFR 63 Subpart CC, §63.640(p) provides an overlap provision that allows the refinery to apply a consistent LDAR program in that a particular process unit.

(p) Overlap of subpart CC with other regulations for equipment leaks.

(1) After the compliance dates specified in paragraph (h) of this section, equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart.

(2) Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa.

(q) 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.

(r) Overlap of subpart CC with other regulations for gasoline loading racks. After the compliance dates specified in paragraph (h) of this section, a Group 1 gasoline loading rack that is part of a source subject to subpart CC and also is subject to the provisions of 40 CFR part 60, subpart XX is required to comply only with this subpart.

Table 2-4 presents a list of process units/areas at the Cherry Point Refinery and their LDAR program applicability drivers.

Table 2-4 LDAR Regulatory Program Drivers

Process Unit	NWCAA 580.8	40 CFR 63 Subpart CC	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGGa	Minor NSR BACT
Crude & Vacuum		X	X		
#1 Reformer		X	X		OAC 977
Naphtha HDS		X			
#2 Reformer		X	X		
Hydrocracker		X		X	OAC 850, OAC 966b
Delayed Coker		X	X		
#1 Diesel HDS		X			OAC 949a
#2 Diesel HDS		X	X		OAC 892b
#3 Diesel HDS		X		X	
Isomerization		X	X		OAC 814b
Light Ends Unit	X		X		
LPG Unit	X		X		
#1 Hydrogen					
#2 Hydrogen				X	
#1 & #2 Calciners					
#3 Calciner					
Utility Boilers					OAC 1001c

Flare Gas Recovery	X	X			
Sour Water Unit				X	OAC 1043
Tank Farm		X			
Chemical Treater		X			
LPG/LEU Loading	X		X		
Truck Rack		X ¹			
Marine Terminal		X ²			
NE Rail Facility		X			OAC 1142

1. In addition to 40 CFR 63 Subpart CC, system leaks are regulated under 40 CFR 63 Subpart R, and monthly leak detection and repair program is required under OAC 527d.
2. 40 CFR 63 Subpart CC requires a LDAR program under 40 CFR 63 Subpart Y.

There are numerous compressors at the refinery, some employing reciprocating and other employing centrifugal compression technologies. Some compressors are subject to the fugitive equipment leak standards through NSPS 40 CFR 60 Subpart GGG or MACT 40 CFR 63 Subpart CC. Both of these subparts reference the standards of 40 CFR 60 Subpart VV. It is noted that under Subpart GGG there is an exemption (§60.593) for compressors in "hydrogen service". To be in hydrogen service, the percent hydrogen in the gas must reasonably expected to always exceed 50 percent by volume. Because of this exemption, only 5 of the 19 refinery compressors are subject to the fugitive equipment leak standards of Subpart VV. These are Flare Gas Recovery compressors 28-1803 and 28-1804, LEU/LPG compressor 22-1801, and Hydrogen Plant compressors 14-1801 and 14-1802.

Compressors subject to Subpart VV are required to be equipped with a seal system that includes a barrier fluid system that prevents the leakage of VOCs to the atmosphere. Of the options available, the refinery selected the option listed under 60.482-3(b)(1) in which the barrier fluid pressure is greater than the compressor stuffing box pressure.

Many of the compressors in hydrogen service have upstream and downstream components such as valves that may be subject to Subpart VV because VOC are contained in the remaining portion of the hydrogen service gas. These include compressors 12-1801, 11-1802, 11-1803, 21-1821, and 21-1822.

There are four process units where NWCAA 580.8 requires a LDAR program because the units have a butane or light feedstock. The non-SIP approved version of NWCAA 580.26 exempts process units from the requirements of Section 580 when they are already required to implement a VOC/HAP control program under federal regulation. Specifically, NWCAA 580.26 states;

580.26 Any petroleum refinery process unit, storage facility or other operation (including drains) subject to federal VOC or HAP standards (NSPS, Benzene Waste NESHAP, Petroleum Refinery NESHAP, etc.) is exempt from the requirements of NWCAA 580.3 through NWCAA 580.10. Such exemption shall take effect upon the date of required compliance with the federal standard.

NWCAA Section 580 was originally adopted by the agency on December 13, 1989. To reduce overlaps between Section 580 and similar requirements under federal regulations the NWCAA amended Section 580 adding the 580.26 exemption. However, for the 580.26 exemption to be federally enforceable it must be adopted into the Washington State Implementation Plan (SIP). To date, this has not been done. Consequently, the AOP includes Section 580.8 requirements for LDAR for applicable process units including one item that is called out 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 BP 2001 Consent Decree requires enhanced LDAR programs throughout the refinery. However, the requirements listed in the consent decree are not considered Title V applicable requirements, and therefore are not listed in this table, or under the specifically applicable requirements in Section 5 of the air operating permit.

2.4 2001 Consent Decree

On August 29, 2001, the BP Consent Decree was entered in the following case.

United States, et. al. v. BP Exploration & Oil, et. al.
Northern District of Indiana, Hammond Division
Civil Action No. 2:96CV 095 RL

This consent decree was issued to BP Exploration & Oil based on alleged violations of federal Prevention of Significant Deterioration (PSD), major New Source Review (NSR), New Source Performance Standards (NSPS) 40 CFR 60 Subparts J and GGG, and National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 61 Subpart FF at various BP owned facilities across the country. The BP Consent Decree includes a compliance schedule with certain compliance obligations applicable to the BP Cherry Point Refinery. However, because these compliance obligations are not considered "requirements" under federal Title V definition, they are not included in the AOP. Most of the compliance dates in the consent decree applicable to the BP Cherry Point Refinery have passed and the refinery has fulfilled the majority of these compliance obligations. These include air pollution control measures such as, but not limited to, applying NSPS Subpart J standards to all refinery fuel gas systems and retrofitting a number of combustion devices with ultra-low NOx burners. To ensure that these projects are federally enforceable after the consent decree "sunsets", the NWCAA has issued orders of approval to construct or regulatory orders for these projects. These NWCAA-issued orders have been incorporated into the AOP as specific requirements.

The consent decree settlement is independently enforceable by the parties to the decree. As such, the consent decree document stands as a separate document from the AOP.

The BP Consent Decree is provided in its entirety on the NWCAA website at www.nwcleanair.org.

2.5 Order of Approval to Construct 211c

On September 18, 2012, the NWCAA issued to Order of Approval to Construct (OAC) 211c as an administrative revision to OAC 211b issued on December 16, 1977, authorizing construction of the #1 and #2 Calciners. The original OAC 211 was issued October 26, 1977, and subsequently revised in November and December of that year.

OAC 211c establishes the following emission limits for combustion units that were in place in 1977 plus the #1 & #2 Calciner that was being permitted at that time.

Particulate: 60 tons per calendar month

Sulfur dioxide: 2,354 lb per hour, calendar month average

The refinery complies with these limits by keeping a monthly record of PM and SO₂ emissions from each subject combustion unit and a cumulative total from all for the month. Because OAC 211c is applicable to numerous emission units at the refinery, it is included in Section 6 of the permit and each effected emissions unit listed in Section 5 of the permit refers to the requirements in Section 6.

2.6 Ecology Administrative Order 7836 Revision 1 (BART Order Rev. 1)

On July 7, 2010, the Washington State Department of Ecology issued Administrative Order 7836 (BART Order) to the BP Cherry Point Refinery in accordance with WAC 173-400-151 and 40 CFR Part 51 Subpart P, the state and federal visibility protection regulations. These regulations require the installation and use of best available retrofit technology (BART) to reduce emissions of visibility-impacting pollutants. The BART order was subsequently modified on August 16, 2013 to remove requirements for Boilers #6 and #7 as they had erroneously been listed in the Order. The August 16, 2013 version of the BART Order includes requirements for the following BART-eligible emissions units.

Process Heaters

- Crude Heater
- South Vacuum Heater
- #1 Reformer Heater
- Naphtha HDS Charge Heater
- Naphtha HDS Stripper Reboiler
- Hydrocracker 1st Stage Reactor Heater (R-1)
- Hydrocracker 1st Stage Fractionator Reboiler
- Hydrocracker 2st Stage Reactor Heater (R-4)
- Hydrocracker 2st Stage Fractionator Reboiler
- South Coker Charge Heater
- North Coker Charge Heater
- #1 DHDS Charge Heater
- #1 DHDS Stabilizer Reboiler
- #1 Hydrogen Plant South Reforming Furnace
- #1 Hydrogen Plant North Reforming Furnace

Sulfur Recovery Complex

- Incinerator
- #2 TGU

Flares

- Low Pressure Flare
- High Pressure Flare

The BART Order also includes green coke handling as a BART-eligible unit. However, because the BART Order does not include any requirements for green coke handling, the AOP does not include any BART Order conditions.

Section 1 of the AOP lists the BART Order when an emissions unit has an applicable requirement under the BART Order. Sections 4 and 5 of the AOP include specific ongoing compliance obligations from the BART Order

At the time the BART Order was written, the Order did not add any new substantive requirements for refinery because the BART review did not identify any best available retrofit technology to employ that was not already in place. For this reason, the conditions of the BART Order are tailored from existing requirements that were applicable at that time the BART Order was written. Sections 4 and 5 of the AOP has been annotated with footnotes linking BART Order conditions to specifically applicable requirement(s) when these requirements served as the original basis of the BART condition. In cases where a condition of the BART Order differs from the original requirement, the BART Order will have its own term in the AOP. The difference may be a result of the original requirement being revised since the BART Order was issued (i.e., an OAC revision), or from the BART Order being written inconsistently from the original requirement.

In accordance with Condition 8 of the BART Order, BP may request that Ecology rescind the BART order after BART eligible units at the refinery have continuously complied with the emissions limitations set forth in the order for three years, the limits are incorporated into OAC, and the limits have been incorporated into the air operating permit.

2.7 NWCAA Regulation Subsection 580.26 Exemption

As first glance it appears that NWCAA 580.26 exempts storage tanks, oily wastewater systems and process units from the VOC control requirements of Section 580, because these areas of the refinery are already controlled for VOC and/or HAP through various federal regulations, including the broad reaching requirements of 40 CFR 63 Subpart CC. Specifically, NWCAA 580.26 states;

580.26 Any petroleum refinery process unit, storage facility or other operation (including drains) subject to federal VOC or HAP standards (NSPS, Benzene Waste NESHAP, Petroleum Refinery NESHAP, etc.) is exempt from the requirements of NWCAA 580.3 through NWCAA 580.10. Such exemption shall take effect upon the date of required compliance with the federal standard.

NWCAA Section 580 was originally adopted on December 13, 1989 in an effort to control VOC emissions from petroleum refineries and other selected industrial sectors. On August 18, 1995, the EPA promulgated 40 CFR 63 Subpart CC "National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries" (Refinery MACT I). In recognition of the significant overlap between the requirements of NWCAA Section 580 and 40 CFR 63 Subpart CC, the NWCAA amended Section 580 on February 8, 1996 adding the 580.26 exemption. However, to make the 580.26 exemption federally enforceable it must be adopted into the Washington State Implementation Plan (SIP) and to date, this has not been done. Therefore, the AOP is written without recognition of this exemption and all requirements of Section 580 are included in the AOP as federally enforceable.

2.8 Ambient Sulfur Dioxide Monitoring Station

An ambient SO₂ monitoring station is located north of the Cherry Point Refinery and just north of Grandview Road. This monitoring station is owned and operated by the refinery. NWCAA Section 460 requires that all air pollution sources with an aggregate heat input capacity greater than 500 MMBtu/hour submit an ambient SO₂ monitoring plan. The aggregate capacity of all heaters and boilers that the Cherry Point Refinery exceeds 500 MMBtu/hour, therefore, the requirements of Section 460 apply. However, because the Section 460 does not explicitly require that the ambient monitoring station be operated, this requirement has been gap-filled in Section 4 of the permit under the term citing NWCAA Section 410 - ambient sulfur dioxide standards.

3 PROCESS DESCRIPTIONS, CONSTRUCTION HISTORY, AND REGULATORY APPLICABILITY

The following section provides a description of each refinery area along with the construction history and regulatory applicability for each process unit or product handling system in that area. The refinery areas are presented in the same order found in the AOP for ease in cross-referencing. The construction history provides a valuable insight into how and why specific requirements were applied during the NSR permitting process. 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. When a one-time requirement is used to determine on-going compliance, such as an initial source test, the results of that activity are provided. 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 SOB. 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.

It is noted that many OACs list a ton per year (tpy) limit for pollutants. Unless the OAC is more specific, e.g., calendar year, the AOP term listing that limit has been described as a "12-month rolling" limit. This is because the basis for the tpy limit is usually PSD avoidance. In addition, unless otherwise specified in the OAC, the MR&R for the permit term has been gap-filled with "directly enforceable" language that requires keeping records of the consecutive 12-month rolling ton value.

3.1 Refinery

The original refinery was constructed in 1970. The project was approved by the NWCAA in an Order of Approval to Construct entitled "Cherry Point Refinery Sulfur Recovery Plant and Certain Heaters and Furnaces" dated June 8, 1970. The order included limits on the fuel type and in some cases the sulfur content for each boiler and process heater being constructed at the following process units that were constructed as the original refinery configuration.

Crude and Vacuum Unit	Light Ends Unit
#1 Reformer Unit	#1 Hydrogen Plant
Naphtha Unit	#1, #2 and #3 Boilers
Hydrocracker Unit	Sulfur Recovery with Incinerator
#1 Diesel HDS Unit	

The order did not include any concentration or mass based emission limits for any of the approved equipment. In addition, the order did not specifically address petroleum storage tanks, wastewater treatment, the marine terminal, the low and high pressure flares, or the #1 Cooling Tower that were all constructed with the original refinery.

On April 12, 2012, the NWCAA issued OAC 1054 superseding the original order dated June 8, 1970. OAC 1054 was written using the agency's current permitting format. The rewrite also clarified the applicable emission units and reworded the conditions for clarity for better incorporation into the AOP.

3.2 Crude/Vacuum Unit

Crude oil processing is the first step in the refinery process. Higher efficiencies and lower costs are achieved if the crude oil separation is accomplished in two steps: fractionating the fresh crude oil at essentially atmospheric pressure; then fractionating the higher-boiling bottoms at a high vacuum. Prior to fractionating, crude oils are "washed" in the desalter to remove salts and other naturally occurring contaminants. The washed crude is then routed through a Pre-Flash Vacuum Tower. The pre-flash tower allows for the vaporization of light hydrocarbons that are subsequently re-introduced into the top of the crude tower to aid in fractionation. The remaining processed crude is heated to about 650° F in the Crude Heater. The heated crude is then routed to the crude tower in which crude is separated by distillation into hydrocarbon fractions according to boiling point. Crude distillation separates and recovers the relatively lighter fractions such as naphtha, stove oil, diesel, and gas oil cracking stock.

The heavier fractions (i.e. "bottoms" or crude residuum) are treated in a vacuum diesel fractionator then heated in two vacuum heaters, the North Vacuum Heater and South Vacuum Heater, to about 760 °F. The heated residuum is processed in the Vacuum Tower. The vacuum separation processes the crude residuum in order to increase the yield of liquid distillates. Light vacuum gas oils and heavy vacuum gas oils are separated and routed to other process units for further processing. The bottoms from the vacuum unit are routed to the Delayed Coker for conversion into coke.

The Crude and Vacuum Unit has three process heaters; the Crude Heater, then South Vacuum Heater and the North Vacuum Heater. All three heaters combust refinery fuel gas supplied by the main mix drum. In addition, the Crude Heater combusts a small volume of gas generated in the vacuum section of the unit called the Vacuum Tail Gas.

Construction History and Regulatory Applicability

The Crude and Vacuum Unit was built with the refinery in 1970. Seven major projects have been undertaken on this unit since 1970. The modifications or additions are: 1) Crude Heater combustion air preheater 2) New North Vacuum Heater; 3) Crude Pre-Flash Project; 4) Crude to Coker Condensate; 5) Crude Fractionation Project; 6) Delayed Coker and #1 & #2 Calciner modifications, and 7) Vacuum Tail Gas amine scrubbing system.

1. Combustion Air Preheater

On February 1975 the refinery proposed to install a combustion air preheater on the Crude Heater to improve energy efficiency by recovering heat from waste heat normally emitted to the atmosphere with the flue gas. The project lowered the stack gas temperature and potentially reduced SO₂ emissions. Dispersion modeling was performed to determine the effects on SO₂ emissions from this project. Model results indicated that ambient air SO₂ emissions would not change as a result of the project. On May 20, 1975, the NWCAA issued OAC 159 approving this project. OAC 159 does not include any specific requirements; therefore, this OAC has not been incorporated into the air operating permit.

2. North Vacuum Heater

In 1983 the refinery installed the North Vacuum Heater with a heat input capacity of 55 MMBtu/hour when the air preheater is in service. The heater was designed with low-NO_x burners. Emissions from this unit were determined to be below the PSD significance thresholds as long as the refinery operated the heater at 55 MMBtu/hour with the air preheater in service or at 77 MMBtu without the air preheater in service. Construction related to the project was approved by the NWCAA on January 14, 1983, under OAC 273.

To meet Best Available Control Technology (BACT) requirements, the heater was equipped with low-NOx burners. NSPS requirements for fuel gas were also triggered which limited the H₂S concentration in the fuel gas not to exceed 162 ppmvd for any three hour period and required continuously monitoring the H₂S concentration. At the time of installation, no EPA-approved continuous H₂S monitor was available. As a result, the refinery took 8-hour samples of the fuel gas for H₂S analysis. The refinery stated that they would install an EPA-approved H₂S monitor when available.

Subsequent heater efficiency studies performed by the refinery indicated that the North Vacuum Heater could be run at higher heat input rates than permitted under OAC 273, and in doing so would provide product splits favoring gas oil production over residual oil production. A PSD analysis was performed by Ecology and a final determination was made that NOx emissions from the project triggered the major PSD threshold. Subsequently, Ecology issued PSD-5 on December 17, 1985, thereby ensuring that the North Vacuum heater was properly permitted under PSD. PSD-5 limited emissions of CO to 9.5 tons/year on an average of any 60 consecutive minutes and NOx to 14.6 lb/hour on an average of any 60 consecutive minutes. The PSD-5 also limited the North Vacuum Heater to a firing rate of 77 MMBtu/hour and the fuel gas feed to a H₂S concentration of 160 ppmv on a 3-hour rolling average. Other requirements of PSD-5 included the installation of continuous monitors for oxygen in the heater stack and H₂S for the refinery fuel gas combusted in the heater.

In addition, PSD-5 required the refinery to offset the increased NOx emissions either by installing a state-of-the-art staged fuel low-NOx burners in the heater during the next unit turnaround or within four years, whichever came first. The PSD permit also included an option of offsetting 28 tons per year of NOx emissions within 12 months elsewhere in the refinery. The refinery selected the latter of the two options for meeting the 28 ton per year NOx netting offset through installation of the Flare Gas Recovery Project. Subsequently, the emissions credits were applied toward that required the offset. The Ecology acknowledged the refinery's fulfillment of PSD-5 Condition 3 for NOx offsets on December 10, 1986. On January 20, 1987, the NWCAA followed suit by providing formal notification of canceling the emission credits as they were used to offset the 28 tons/year in NOx emissions.

In 1995, the refinery requested a revision to PSD-5 to update CO emissions. During the time of the original PSD application, AP-42 did not have a CO emission factor for heaters with low-NOx burners and the application used an emission factor for an uncontrolled heater. By 1995, AP-42 had been revised to include a CO emission factor for low-NOx burners that was higher than that for uncontrolled heaters. As a result, the refinery requested that the CO emission limit in PSD-5 be increased from 9.5 to 16.6 tons per year. At that time the Ecology and NWCAA recognized that CO was not a PSD level pollutant and that the CO limit was more appropriately addressed in the minor NSR OAC permit. As a result on February 2, 1995, the NWCAA issued OAC 273 Revision 1 (or "a") with a 16.6 ton per year CO limit as its only substantive permit condition. On February 6, 1995, the Ecology issued PSD-5 Amendment 1 rescinding the CO limit from the PSD permit.

On November 18, 2004, OAC 273 was revised (Revision b) to adjust the CO emission limit on the heater from 16.6 to 27.7 tons per year to reflect an updated and more accurate emission factor of 0.0823lb/MMBtu as provided in AP-42 for this type of process heater. The revision also added a cumulative 12-month rolling period to the CO limit and an associated recordkeeping requirement.

On January 22, 2009, Ecology issued PSD-5 Second Amendment. This amendment clarified that the firing rate limit for the North Vacuum Heater was based on a 30-day rolling average. This longer averaging time was needed to accommodate variability in the heater duty inherent in variable operating conditions such as weather or beginning verse end of run conditions in the Crude and Vacuum Unit. The second PSD amendment also removed the requirement to offset 28

tons per year of NO_x emissions because this reduction had been documented in NWCAA's March 18, 1986 regulatory order to BP.

3. South Vacuum Heater

The South Vacuum Heater was retrofitted with low-NO_x burners in 1999 as required by OAC 689 to offset increased NO_x emissions from the #1 & #2 Calciner production increase project approved under OAC 689. In early 2005, the South Vacuum Heater convection section was reconstructed and the heater was equipped with ultra low-NO_x burners (ULNB) due to operability issues with the low-NO_x burners installed previously. The ULNB retrofit approved under OAC 902 allowed the refinery to reduce NO_x emissions as part of their 2001 Consent Decree commitment to install NO_x controls on 30% of the heater capacity at the refinery. The project resulted in the heater being de-rated from 222 MMBtu/hour to 207 MMBtu/hour.

The initial NO_x CEM certification and source testing revealed that the original NO_x emission limits in OAC 902 were too strict. Revised OAC 902a was issued on November 1, 2005 to remove the ppm limit and increase the pound per hour limit, thereby reducing the NO_x reduction credits for this project by 7 tons per year. The removal of the ppm limit eliminated the need to add a startup provision in the OAC. OAC 902a also specified that Conditions 1.3.1, 1.3.2, 2.3.1 and 2.3.2 of OAC 689 were void upon startup of the South Vacuum Heater following completion of the South Vacuum Heater Improvement Project. On May 24, 2005, the NWCAA received notice that the ULNB retrofit project was complete and that the South Vacuum Heater restarted on May 19, 2005, thereby, voiding the prior NO_x and CO requirements of OAC 689. Because Conditions 1.3.1, 1.3.2, 2.3.1 and 2.3.2 of OAC 689 are void, they were removed from OAC 689 in revision "b".

4. Crude Pre-Flash Project

On January 27, 1987, the refinery submitted a Notice of Construction for a new pre-flash vessel and a new vacuum diesel fractionator (VDF). It was calculated that the project would result in no net increase in emissions. Based on the NWCAA review of the application, it was determined that a Notice of Construction was not required for the project.

5. Crude to Coker Condensate

On April 4, 1990, the refinery submitted a proposal for the Crude to Coker Condensate project. The project was designed to route crude oil directly to the Delayed Coker in response to changing characteristics of the crude oil feed stocks. The project would increase the firing rates of various heaters in the refinery including those in the Reformers, Diesel and Naphtha units. The project did not include any physical changes to the heaters that would increase their pre-project design capacity. In their project submittal, the refinery proposed to install low-NO_x burners in three heaters to mitigate NO_x increases from the anticipated increase in heater firing rates. However, on August 8, 1990, the NWCAA issued a letter (OAC 281) stating that the project did not require approval because the affected heaters would not be firing above their design capacity. Subsequently, the refinery decided not to install the low-NO_x burners. The August 8, 1990 NWCAA letter does not include any requirements and is not referenced in the air operating permit.

6. Crude Fractionation Project

On November 19, 1997 the refinery submitted a Notice of Construction to the NWCAA for improving crude fractionation and slightly increasing crude processing capacity. The project included modifications to the existing preheat exchange train and additional preheat exchangers, replacement of the existing pre-flash drum, replacement of the existing debutanizer tower with a larger tower, conversion of the existing pre-flash drum to a stove oil stripper, and the

replacement of the existing vacuum tower. These modifications also required changes to pumps, heat exchangers, and process relief valves.

On May 1, 1998, the NWCAA issued OAC 640 approving the Crude Fractionation Project. The OAC identified BACT as a LDAR program conducted in accordance with 40 CFR 60 Subparts GGG and VV for specific equipment at the Crude and Vacuum Units that were being modified as part of the Crude Fractionator Project. The units included the Crude Distillation Unit, Butane Distillation Unit, Stove Oil Stripper, Diesel Oil Stripper, Vacuum Diesel Fractionation Unit (VDF), and Vacuum Distillation Unit.

On May 9, 2012, the NWCAA issued revised OAC 640a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit. OAC 640a includes a single condition requiring a startup notice following completion of the project. The NWCAA received this startup notification on May 18, 1999, stating that the Crude Fractionation Project was completed, and that the Crude Unit would startup in June 1999. Because this single and one-time only requirement of OAC 640a has been completed, OAC 640a is not cited in the air operating permit.

7. Delayed Coker and #1 & #2 Calciner Modifications

This project affected the South Vacuum Heater in the Crude and Vacuum Unit and the Vacuum Tail Gas overhead system. Increases in NO_x emissions associated with the project were offset by the installation of low-NO_x burners in the South Vacuum Heater approved under OAC 689 in 1999. Increases in SO₂ emissions associated with this project were off-set by the installation of a diethanolamine (DEA) scrubber in the Vacuum Tail Gas overhead system. On October 27, 2008, revised OAC 689a was issued to restructure limits on the North and South Coker Charge Heaters but no changes were made to conditions that applied to the South Vacuum Heater and Vacuum/VDF Overhead Tail Gas DEA Scrubber.

Low-NO_x burners were installed in the South Vacuum Heater in 1999. On June 29, 1999 the Vacuum Tail Gas amine scrubber began operating. Performance tests were performed on August 17, 1999, demonstrating that the scrubber achieved a greater than 80% H₂S reduction as required by OAC 689. Performance certification tests for NO_x and CO emissions were performed on South Vacuum Heater on September 22, 1999.

On September 18, 2012, the NWCAA issued OAC 689b. This revision made changes to clarify conditions and to clean up the order prior to incorporation into the air operating permit. Revision OAC 689b removed NO_x and CO conditions for the South Vacuum Heater that were established following the low-NO_x burner retrofit in 1999 because in 2005, the South Vacuum Heater was retrofit with ultra-low NO_x burners (ULNB) approved under OAC 902. On May 24, 2005, the NWCAA received notice that the ULNB retrofit project was complete and that the South Vacuum Heater was restarted on May 19, 2005.

8. Vacuum Tail Gas

Prior to installing the DEA "amine" scrubber to treat Vacuum Tail Gas generated at the Vacuum Diesel Fractionator (VDF) and Vacuum Tower with the absorbed H₂S routed to the Sulfur Recovery Unit for conversion into elemental sulfur the untreated Vacuum Tail Gas was routed to the main refinery fuel gas system and/or routed directly into the Crude Heater as supplemental fuel. The purpose of the project was to improve VDF and Vacuum Tower performance by establishing pressure controls on the tower overheads and to reduce SO₂ emissions from the Crude Unit with the reductions used for PSD netting offsets.

The Vacuum Tail gas amine scrubbing project was approved April 13, 1999, under OAC 689. The scrubber was installed and began operating in June 29, 1999. The 80% SO₂ reduction required in the OAC was used for PSD netting of the Delayed Coker and #1 & #2 Calciner

Modification project. The 80% reduction of SO₂ emissions from Vacuum Tail Gas scrubbing was estimated to result in a net decrease in SO₂ emissions of 515 tons per year.

In 2005, Vacuum Tail Gas that was being combusted in the Crude Heater was rerouted to the main refinery fuel gas mix drum. This was done so that the Crude Heater could be operated in compliance with the requirements of 40 CFR 60 Subpart J because the Vacuum Tail Gas was not being continuously monitored for H₂S in accordance with Subpart J. On April 10, 2008, US EPA Region 10 issued a temporary, 18 month, alternative monitoring plan (AMP) for Subpart J allowing combustion of Vacuum Tail Gas in the Crude Heater without a CEMS. The AMP required that the Vacuum Tail Gas be periodically monitored for H₂S using draeger tube sampling. Upon issuance of the AMP, the Vacuum Tail Gas was rerouted back to the Crude Heater as a supplemental fuel source in that heater. The AMP expired on October 10, 2009. Just prior to this expiration date, a CEMS was installed to continuously monitor H₂S in the Vacuum Tail Gas in accordance with the requirements of Subpart J.

9. South Vacuum Heater, Ultra-Low NO_x Burner Project

On February 7, 2005, the NWCAA issued OAC 902 approving installation of ultra-low NO_x burners (ULNB) in the existing South Vacuum Heater. BP retrofitted the South Vacuum Heater with the ULNB and restarted the heater on May 19, 2005. On November 1, 2005, OAC 902a revision was issued. A CEM was installed to demonstrate compliance with the NO_x emission limit of 10.5 lb/hour, calendar day average. BP demonstrated compliance with the CO limit with an initial, one-time only source test conducted on June 14, 2006. The test measured 0.15 lb/hour CO, significantly below the OAC 902a CO emission limit of 11.8 lb/hour.

3.3 Reformer Units and Naphtha HDS

The Reformers and Naphtha units are used to increase the octane rating of hydrocarbons by converting straight chain hydrocarbons into aromatic and branched chain hydrocarbons. Prior to the reformers, naphtha feed stock from the Crude Unit and Delayed Coker is processed by hydro-desulfurization in the Naphtha HDS unit. Naphtha is mixed with molecular hydrogen (H₂), heated to 500 °F and passed over a catalyst to hydrogenate unsaturated chemical bonds and liberate sulfur and other impurities. Typically, organic sulfur compounds are converted to H₂S and organic nitrogen is converted to ammonia (NH₃). Removal of sulfur from the naphtha allows further processing in the Hydrocracker and Reformers because the catalysts involved in those processes can be poisoned by sulfur. The treated naphtha is then routed to Reformers for the production of higher octane products. This conversion takes place with H₂ again at about 700°F, under pressure, and in the presence of a catalyst. Also, waste heat from the reformers may be used to generate steam for refinery-wide use.

In response to EPA's effort to eliminate lead from gasoline, the refinery added an additional reformer that would upgrade low octane components into high octane components for use in the gasoline blending system. As a result, the refinery discontinued the use of tetra-ethyl lead as a means to boost octane in gasoline products. In 1996 the refinery added a light reformate splitter (LRF) tower to the #1 Reformer Unit. The purpose of the LRF is to reduce the benzene content of the light reformate overhead and produce a concentrated benzene bottom product that can be sold primarily to the chemical manufacturing industry as a reaction agent.

Reformer catalyst in the #1 and #2 Reformers is regenerated approximately once every six months. During catalyst regeneration, the process feed is stopped and the heater is put into hot stand-by operation. A hydrogen sweep is done to remove excess hydrocarbons and the gasses are sent to flare. During catalyst regeneration, the catalyst goes through a burn-off process step and then an oxy-chlorination step. The burn-off process removes material attached to the catalyst and removes any impurities. The oxy-chlorination step reactivates the catalyst using a chlorinated solvent. As the catalyst is brought back up to temperature, a large amount of hydrogen chloride (HCl) is released. During catalyst regenerations, gasses are scrubbed to

remove the HCl at an approximate 98% efficiency rate before routing to the flare system. The catalyst regeneration process can be completed within about three days.

Major equipment at the Reformers and Naphtha unit include: Naphtha HDS Charge Heater, Naphtha HDS Stripper Reboiler, #1 Reformer Heater, #2 Reformer Heater, and Light Reformate Fractionator (LRF). The unit has numerous components in heavy liquid, light liquid, and gaseous service that may emit VOCs and HAPs.

Construction History and Regulatory Applicability

The #1 Reformer, Naphtha HDS Charge Heater, and Naphtha HDS Stripper Reboiler were built with the refinery in 1970. As a condition of construction the Naphtha HDS Charge Heater was required to burn fuel gas only (OAC 1054). Four projects have been performed in this area since original construction: 1) Gasoline Reformer Unit; 2) New Light Reformate Splitter Tower; 3) Crude to Coker Condensate, and 4) #1 Reformer Recycle Gas Dryer project.

On January 22, 2007, the NWCAA issued OAC 977 for the #1 Reformer Recycle Gas Dryer project. The project shortened the time period for regenerating the reformer catalyst. The OAC required an enhanced LDAR program at the unit, and required that the #1 Reformer Heater be source tested for NO_x. The one-time only NO_x test was completed on June 26, 2007. The other projects are described under the #2 Reformer Unit.

According to the refinery's determination, the Naphtha HDS is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors. The refinery also determined in their Refinery MACT Initial Notification of Compliance Status Report submitted on July 25, 2002 that #1 Reformer and #2 Reformer are each subject to 40 CFR 63 Subpart UUU.

1. #2 Reformer Unit

In 1985, the refinery submitted a Notice of Construction (NOC) application to construct the #2 Reformer, including the #2 Reformer Heater with nominal heat input capacity of 340 MMBtu/hour. The project was also referred to as the "Gasoline Reformer" project. The project allowed the refinery to phase out the tetra-ethyl lead as an octane enhancer in gasoline as mandated by federal requirements by 1986. The #2 Reformer upgrades low octane components into high octane components. An additional Naphtha HDS Heater with a rated heat input capacity of 60 MMBtu/hour was proposed in the NOC application. However, the heater was never built.

The #2 Reformer project was approved under OAC 305 issued November 14, 1985. On May 3, 2012, the NWCAA issued revised OAC 305a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

On March 13, 1986, Ecology issued PSD-7 approving the #2 Reformer. According to the Finding section of PSD-7, "Oxides of nitrogen are the only emissions which are subject to PSD review". However, PSD-7 contains specific limits on CO and NO_x from the #2 Reformer Heater. It also limits the concentration of H₂S contained in fuel gas combusted in the #2 Reformer Heater.

PSD-7 Conditions 1 through 5, and 10 are included in the AOP as ongoing requirements. Condition 8 is not listed in the AOP because it is considered administrative only. Conditions 6, 7 and 9 are considered one-time only requirements that have been met and are therefore not included in the AOP. Condition 6 requires initial NO_x source testing on the #2 Reformer Heater that was completed. Condition 7 requires that construction of the project commence within 18 months of PSD-7 issuance, which did occur. Lastly, Condition 9 requires that the NWCAA be notified in writing within 30 days of startup of the project. The NWCAA received this startup notice on September 10, 1987. The notice stated that the #2 Reformer Unit startup date was August 14, 1987.

The PSD and OAC approvals addressed combustion emissions from the #2 Reformer Heater and fugitive emissions from process equipment leaks at the #2 Reformer Unit. BACT for the heater was determined to be the use of low-NOx burners with air preheat and computer controlled oxygen trim. NSPS 40 CFR 60 Subpart J requirements were triggered for the project requiring continuous monitoring of the H₂S concentration in the refinery fuel gas combusted in the #2 Reformer Heater, with an associated 162 ppmvd H₂S, 3-hour rolling average. PSD-7 also includes a 90 ppm H₂S limit, monthly average, as BACT. PSD-7 established short-term (lb/hr) and long-term (tpy) NO_x and CO limits for the #2 Reformer Heater. However, because the permit did not specify a method for determining ongoing compliance with these limits, the associated terms in the AOP have been gap-filled with directly enforceable requirements to conduct source testing for NO_x and CO biennially.

2. Light Reformate Splitter Tower (LRF Tower)

In August 1995, the refinery proposed to construct a new Light Reformate Splitter Tower at the #1 Reformer Unit. The project included reconfiguring the existing reformate splitter so that the light reformate overhead would be drawn off and become the feed to the LRF Tower. The project was designed to produce C5/C6 paraffin overhead that would be used for gasoline blending and benzene concentrated (40% by weight) bottoms that would be stored in existing tanks prior to shipping off-site. The project would result in an increase in VOC and benzene emissions both from new equipment at the #1 Reformer Unit and from existing storage tanks handling products with relatively high in benzene concentrations.

The NWCAA determined that a WAC 173-460 Air Toxics, Second Tier (Tier II) analysis was required prior to approval of the project because modeling showed that benzene would exceed the acceptable source impact level (ASIL). A Tier II analysis was performed by Ecology and the project was approved based on a decision that proposed emissions controls represented Toxic Best Available Control Technology (T-BACT) and that the project would not result in an increased cancer risk of more than one in one hundred thousand.

On September 7, 1995 the NWCAA granted the refinery approval for the beginning of site preparation work, although the refinery was prohibited from actually installing and constructing the LRF tower until an approval order was issued. On January 3, 1996, the NWCAA issued OAC 562 approving the project.

On February 14, 1996, the refinery requested a change to their Order of Approval that would allow the use of larger tanks for storage of the benzene-concentrated LRF Tower bottoms. All of the tanks have similar construction and are equipped with emission controls. The refinery also proposed that they would use only one of these sixteen tanks at a time. Emissions were expected to increase slightly as a result of this change. The requested change was incorporated into the Tier II analysis. On February 26, 1996, the NWCAA issued revision OAC 562a approving the change. The revised OAC included a new condition that specified those tanks that were allowed to store the benzene concentrate. On April 26, 1996, Ecology issued a Tier II Analysis Fact Sheet in support of the revised project.

The project was constructed and the new LRF Tower began operating on May 6, 1996. Once installed and operating, the refinery determined that through computer operation optimization the LRF Tower bottoms could be further concentrated to 70% by weight benzene, much better than the 40% by weight design. No changes to the equipment were proposed, and no increase in benzene emissions was anticipated. The refinery re-calculated benzene exposure levels for off-site receptors and determined the cancer risk from the project was similar to the original calculations. On March 9, 2000, the NWCAA determined that new source review was not required as a result of this change.

On December 8, 2000, the NWCAA issued OAC 562b which allowed transfers of the benzene concentrate between any two of the approved tanks to facilitate periodic inspection and maintenance of the tanks. On March 17, 2003, the NWCAA issued OAC 562c with a revised list

of tanks that were allowed to transfer benzene concentrate. On July 9, 2012, the NWCAA issued revised OAC 562d. This revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3. Crude to Coker Condensate/COUP

Other construction projects affecting the Naphtha HDS were the Coker Olefin Upgrade Project (COUP) and the Crude to Coker Condensate Project both discussed under the Delayed Coker. The Crude to Coker Condensate project recovered waste heat from the Delayed Coke drum overhead gas and used it to pre-heat incoming crude oil at the Crude Unit. Additional heater firing takes place at several units including the Naphtha HDS and Reformer units. The COUP resulted in heat exchangers and pumps being replaced and a new hot flash drum installed. The COUP triggered regulatory requirements for the modified equipment. In a letter dated August 8, 1990, the NWCAA determined that the equipment components affected by the Crude to Coker Condensate Project were subject to 40 CFR 60 Subpart GGG as a result of the COUP.

3.4 Hydrocracker

Hydrocracking is a process that uses temperature, pressure, hydrogen, and catalyst to convert gas oil materials into product streams such as gasoline, blending components, Reformer feeds, and jet fuel. Typically, vacuum gas oil from the crude/vacuum and delayed coker units is reacted with hydrogen under pressure in the presence of a catalyst. Hydrocracking removes sulfur and nitrogen compounds and produces more valuable lower molecular weight hydrocarbons. Butane and refinery fuel gas are by-products of this process.

The Hydrocracker at the Cherry Point Refinery has two stages. The 1st stage of the Hydrocracker cracks a portion of the feed to product and the 2nd stage cracks the remaining feed to product. Products from the Hydrocracker are processed further in the Reformers and are used in blending fuels. Both stages make Heavy Hydrocrackate (HUX) which is reformer feed.

Major equipment at the Hydrocracker includes the 1st Stage Reactor Heater (R-1), 1st Stage Fractionator Reboiler, and 2nd Stage Reactor Heater (R-4) and the 2nd Stage Fractionator Reboiler. This unit has a number of components in heavy liquid, light liquid and gaseous service that can emit fugitive VOCs and HAPs. Other components of the Hydrocracker that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

Construction History and Regulatory Applicability

The original Hydrocracker unit was built with the refinery in 1970. On November 20, 1974, the NWCAA issued OAC 148 and OAC 149 approving the installation of air pre-heaters on the Hydrocracker 1st Stage Fractionator Reboiler and Hydrocracker 2nd Stage Fractionator Reboiler, respectively. These approval orders are considered narrative and do not include any specific requirements. Therefore, they have not been incorporated into the air operating permit.

In early 2001 the refinery installed a number of skid mounted gas turbine generators to provide affordable and reliable electrical power during a period of high energy prices and potential power shortages. Even though the gas turbines were removed from the refinery in July 2002, their approval was contingent on the refinery offsetting NOx emissions from the turbines by installing low-NOx burners on the 2nd Stage Fractionator Reboiler as approved under Administrative Order on Consent (CAA-10-2001-0096) issued by EPA Region 10. Condition 9a of the order states, "ARCO will retrofit the second stage hydrocracker fractionation reboiler with low NOx burners during the first scheduled maintenance shutdown (turnaround) of that unit after June 1, 2001 but in no case later than May 31, 2004." On November 13, 2003, the NWCAA issued OAC 847 approving a low-NOx burner retrofit project for the Hydrocracker 2nd Stage Fractionator Reboiler. The OAC established a 0.07 lb/MMBtu NOx limit for the reboiler and 56.2 ton/year annual mass based limit with compliance demonstrated through annual source testing.

On October 27, 2008 the NWCAA issued revised OAC 847a. The revision corrected the test method used for determining visual emissions from the 2nd Stage Fractionator Reboiler. In addition, the revision added a firing rate limit of 183.4 MMBtu/hour based on a 720-hour averaging period. This allows the reboiler to fire over the 183.4 MMBtu/hour limit for short-term periods to accommodate variability in duty. This operational flexibility was needed because the reboiler duty fluctuates substantially based on production rates, catalyst health, crude slate, feedstock temperature, fuel gas composition, end-of-run versus start-of-run conditions and weather.

On July 17, 2012, the NWCAA issued revised OAC 847b. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

On August 9, 2006, the NWCAA issued OAC 966 approving a retrofit of the Hydrocracker 1st Stage Reactor Heater (R-1) with ultra-low NO_x burners (ULNB). This project was done to achieve NO_x reductions for the 2001 Consent Decree. OAC 966 established a NO_x limit for the heater and required that ongoing compliance be demonstrated with a CEM. As stated in a startup notification letter from BP dated October 30, 2006, the heater restarted with the ULNB on October 29, 2006. This startup notice fulfilled Condition 7 of OAC 966 and therefore, this one-time only condition is not included in the AOP.

On January 29, 2008, the NWCAA issued revised OAC 966a. This revision corrected the EPA test method prescribed for annual CO source testing.

On April 21, 2011, the NWCAA issued revised OAC 966b. This revision established a firing rate limit on the Hydrocracker 1st Stage Reactor Heater of 120.9 MMBtu/hour HHV, based on a 30-day rolling average. The revision increased the NO_x short-term mass emission rate limit from 3.6 to 4.9 lb/hour, and added recordkeeping requirements to document ongoing compliance with NO_x and CO limits of the OAC.

On December 1, 2003, the NWCAA issued OAC 850 approving the Hydrocracker Incremental Vacuum Gas Oil Production Project. The project increased feed rate at the Hydrocracker. The only requirement of OAC 850 was a condition to implement an enhanced LDAR on equipment components associate with the project. OAC 850 includes a project summary that states that the incremental gas oil project will increase the gas oil processing rate by 2,600 barrels per day (bpd). This project summary statement is not considered an applicable requirement and as such is not included in the AOP.

On January 14, 1992, the NWCAA issued OAC 351 authorizing construction of the #4 Boiler at the refinery. As a PSD offset project, OAC 351 required a 27 ton per year NO_x reduction at the Hydrocracker 1st Stage Fractionator Reboiler with a low-NO_x burners retrofit project. On May 28, 1993, the refinery submitted a letter to the NWCAA stating that the NO_x reductions associated with the 1st Stage Fractionator Reboiler low-NO_x burner project had been validated through pre-project and post project source testing. The NWCAA sent a letter to the refinery dated March 7, 1994, stating that a review of the source test data confirmed that the required 27 ton NO_x reduction had been met.

On May 10, 2010, the NWCAA issued revised OAC 351e authorizing the refinery to modify the flue gas recirculation system on the #4 Boiler that was being done for Consent Decree creditable NO_x reductions. Consistent with the original OAC, OAC 351e includes the following condition applicable to the Hydrocracker 1st Stage Fractionator Reboiler.

11. A contemporaneous decrease in NO_x emissions of at least 27 tons per year shall be realized by installation of low-NO_x burners on the Hydrocracker Unit 1st Stage Fractionator Reboiler. The refinery shall document the decrease by a source emission test for NO_x in conformance with EPA Method 7A or 7E.

On November 29, 2010, the NWCAA issued OAC 1067 authorizing replacement of the low-NO_x burners on the Hydrocracker 1st Stage Fractionator Reboiler with state-of-the-art ULNB. This NO_x reduction project was approved as a PSD netting offset project for the BP Clean Fuels Project approved under OAC 1064. OAC 1067 revision "a" was issued July 29, 2011 allowing the CO lb/hour limit to be the compliance demonstration method when the CO lb/MMBtu limit is exceeded. The effective date of OAC 1067a is the startup date of the 1st Stage Fractionator Reboiler following the ULNB retrofit project. On June 4, 2012, the NWCAA received a letter from BP notifying the agency that the reboiler began operating on May 16, 2012, following installation of the ULNB. This fulfills this one-time only notice of startup requirement of OAC 1067a Condition 11. As stated in OAC 1067a, Condition 11 of OAC 351e that requires that the 1st Stage Fractionator Reboiler demonstrate compliance with a 27 ton per year NO_x reduction from a 1994 low-NO_x burner retrofit project is superseded upon startup of the reboiler with the ULNB. Therefore, Condition 11 of OAC 351e is not incorporated into the AOP because it has been superseded.

On April 9, 2012, the NWCAA issued OAC 1122 approving the Hydrocracker Atmospheric Relief Valve (ARV) Project. The project involved routing a large emergency atmospheric relief vent to a new knockout vessel and then to the flare gas system. The project triggered NSPS Subpart GGGa applicability requiring the refinery to employ an enhanced LDAR program at the Hydrocracker Unit. OAC 1122 has only one condition that requires that the agency be notified of the startup date of the Hydrocracker Unit following completion of the ARV project. On May 17, 2012, the NWCAA received a letter from BP notifying the agency that the Hydrocracker Unit restarted on May 16, 2012, following completion of the ARV project. Because the one-time only requirement of OAC 1122 has been fulfilled, OAC 1122 is not cited in the air operating permit.

3.5 Delayed Coker

In many refineries, vacuum tower bottoms are sold as fuel oil. However, the BP Cherry Point Refinery converts vacuum tower bottoms to petroleum coke for off-site sale for electrode usage. Coking takes place at about 900°F in one of four coker drums. Vacuum residuum from the crude unit is decomposed (cracked) into lighter 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. Feedstocks to the coker include slop oil recovered from the API separator and other hydrocarbon sludges and wastes in addition to vacuum tower bottoms. Naphtha and gas oils are produced along with the coke and are routed to other refinery units for processing and finishing.

After coking, the coke is removed from the drums by high pressure steam and water. The coker vents are opened for unloading once the drum pressure is less than 5 psig. Coke and water are separated by screens. The water is routed to an API separator where the fine coke particles are recovered and recycled back into the coker. The extracted coke, referred to as "green" coke, is then either calcined in the refinery's Calciner or sold as a final product.

Approximately once every six months, the tubes in the North and South Coker Charge Heaters need to be cleaned because solid carbonaceous deposits known as "coke" form over time. While coking in the drums is desired, the coking of other surfaces is deleterious. Coke in the charge heater tubes interferes with the heat transfer and velocity profile of the residuum being transferred from the heater to the coke drums. The heaters are taken out of service one at a time, steam cleaned and allowed to cool. A cleaning device called a pig is sent through each of the charge heater tubes to remove the coke deposits and collect wall thickness data on the tubes to ensure continued safe operations. Weak and worn tubes are replaced prior to restarting the heater.

Under normal operations, the coker blow down vapor recovery (CBVR) system collects the gasses emitted from coking operations. These gasses are routed through a series of drums,

compressed and directed through a MDEA absorber to remove H₂S. However the Pressure Safety Valves (PSVs) on the CBVR system are set at relatively low pressures to protect the coke drums. The steam cleaning phase of the heater shut down sequence occurs at pressures that exceed the PSV settings on the CBVR system. As a result the CBVR system is not used during the steam cleaning phase. Instead, the gasses emitted when the tubes are being de-cooked are directed into the low pressure flare header where they are recovered by the flare gas recovery compressors and routed through its associated absorber to remove H₂S. During this operation, the high pressure compressor and low pressure compressors are both lined up to collect gasses from the low pressure header to ensure that sufficient recovery capacity is available.

Major equipment at the Delayed Coker includes the North Coker Heater, the South Coker Heater, and Coker Fractionator. This unit has a number of components in heavy liquid, light liquid and gaseous service that can emit fugitive VOCs and HAPs. Other elements of this unit that may result in emissions to the air include pumps, valves, flanges, vents, sewer line connections and pressure relief devices.

Construction History and Regulatory Applicability

The original Delayed Coker was built with the refinery in 1970. Three major projects have been performed on the Delayed Coker since original construction: 1) Crude to Coker Condensate; 2) Coker Olefin Upgrade Project (COUP); and 3) Modification of Coker Unit, and #1 & #2 Calciner Hearths. According to the refinery's determination, the Coker unit is subject to 40 CFR 63 Subpart CC Refinery MACT for Group 1 valves, pumps, and compressors.

The following is a discussion of each project.

1. Crude to Coker Condensate

On April 4, 1990, the refinery submitted a proposal for the Crude to Coker Condensate project. The project was designed to route crude oil directly to the Delayed Coker in response to changing characteristics of the crude oil feed stocks. The project would increase the firing rates of various heaters in the refinery including those in the Reformers, Diesel and Naphtha units. The project did not include any physical changes to the heaters that would increase their pre-project design capacity. In their project submittal, the refinery proposed to install low-NOx burners in three heaters to mitigate NOx increases from the anticipated increase in heater firing rates. However, on August 8, 1990, the NWCAA issued a letter (NOC 281) stating that the project did not require approval because the affected heaters would not be firing above their design capacity. Subsequently, the refinery decided not to install the low-NOx burners. The August 8, 1990 NWCAA letter does not include any requirements and is not referenced in the air operating permit.

2. Coker Olefin Upgrade Project (COUP)

In 1990, the refinery proposed the Coker Olefin Upgrade Project (COUP) which was designed to improve recovery of light portions and naphtha at the Delayed Coker. At the time of the proposal, coker naphtha from the high pressure separator in the Delayed Coker was stabilized and routed to the Naphtha HDS Unit for treatment and removal of sulfur compounds. The COUP proposed to install equipment at the Delayed Coker to recover high octane, light coker naphtha streams for gasoline blending by installing a new dehexanizer tower downstream of the Delayed Coker's high pressure separator to recover hexane and lighter portions of the coker naphtha. The lighter portion was debutanized in the existing coker stabilizer and further processed in the Merox Unit (note, the Merox Unit was decommissioned in 2005 following startup of the Isomerization Unit). Minor changes to the Naphtha HDS unit were also required including new heat exchangers, pumps, and the installation of a hot flash drum upstream of the cold flash drum.

On May 15, 1990, the NWCAA issued a letter (NOC 283) stating that the Coker Olefin Upgrade Project (COUP) was reviewed under a "Notice of Intent", as opposed to the Notice of Construction (NOC) application review process required for an Order of Approval to Construct (OAC). The letter is not signed and is not considered an OAC. The letter includes a number of conditions that are reiterations of already applicable federal requirements. These include 40 CFR 60 Subpart GGG requirements at the Delayed Coker, and 40 CFR 60 Subpart QQQ requirements at the Wastewater Treatment Plant. Because the May 15, 1990 letter does not add any requirements not already required by direct federal applicability, and the fact that the letter is not considered an enforceable order issued under NWCAA Section 300, the letter and its conditions are not referenced in the air operating permit.

3. Delayed Coker and #1 & #2 Calciner Modifications

On December 9, 1998 the refinery notified the NWCAA of proposed modifications to the Delayed Coker and #1 & #2 Calciners. This project was part of an effort to debottleneck the coker process. When completed, calcined coke production could increase. Additionally, the project would allow for other refinery units to increase production without having to make equipment modifications. To complete the project, there was an increase in the heat input capacity of the North and South Coker Charge Heaters and replacement of the four coke drums with larger drums. The coker heaters were retrofitted with staged air combustion and flue gas recirculation technology to control NO_x emissions

Modifications to the Delayed Coker originally included rerouting fuel gas generated at the Merox Unit to supplement the refinery fuel gas stream being combusted in the North and South Coker Charge Heaters. In early 2005, the Merox Unit was decommissioned following startup of the Isomerization unit. As a result, the fuel gas stream combusted in the Coker Charge Heaters is now comprised of gas generated at the Delayed Coker supplemented by gas from the refinery's main fuel gas drum. Since 1999, the H₂S content of this "coker fuel gas" has been monitored with a CEM that was installed under approval Condition 2.5.1 of OAC 689.

Calciner modifications included increasing the heat capacity of #1 & #2 Calciner hearths as well as requiring BACT as a caustic scrubber followed by a wet electrostatic precipitator.

Emissions from the Delayed Coker and #1 & #2 Calciner Modification project included NO_x, CO, SO₂, PM, and VOCs. Of these pollutants, only NO_x was determined to be above PSD thresholds. The refinery modified the project to include retrofitting the South Vacuum Heater with low-NO_x burners to offset the NO_x increase and avoid PSD review. The refinery also proposed to off-set increased SO₂ emissions by installing a DEA scrubber in the Vacuum Tail-Gas overhead system. As a result, net emission increases were determined by the NWCAA to be below PSD significant thresholds for all criteria pollutants. Section 3.3 presents a detailed description of the Crude/Vacuum Unit modifications to the South Vacuum Heater and Tail-Gas Overhead System.

On April 13, 1999, the NWCAA issued OAC 689 approving modifications to the Delayed Coker and #1 & #2 Calciners. The OAC set short-term (lb/hr) and long-term (tpy) limits for NO_x, SO₂ and CO on the North and South Coker Charge Heaters. It also set a 5% opacity limit on the heater stacks and established a 50 ppmvd daily average limit for H₂S in the fuel gas combusted in the Coker Heaters.

The Delayed Coker and #1 & #2 Calciner Modification project was completed by the end of June 1999 and the units restarted.

On October 27, 2008 the NWCAA issued revised OAC 689a. The revision converted the SO₂, CO, and NO_x emission limits for the North and the South Coker Charge Heaters from lb/MMBtu to the equivalent lb/hr limit based on the full firing rate for each heater. This simplified reporting and clarified that emission limits are on a per heater basis, instead of on the combination of both heaters.

On September 18, 2012, the NWCAA issued OAC 689b. This revision made changes to clarify conditions and clean up the order prior to incorporation into the air operating permit.

3.6 Diesel Hydrodesulfurization Units

Construction History and Regulatory Applicability

The #1 Diesel HDS Unit (#1 DHDS) was built with the refinery in 1970. Construction of the #2 Diesel HDS Unit (#2 DHDS) was completed in 2006, with startup occurring on May 22, 2006. The #3 Diesel HDS Unit (#3 DHDS) is currently under construction with a startup date scheduled for early 2013.

1. #1 Diesel HDS Unit

Diesel feed stock from the Crude and Vacuum Unit and Delayed Coker is processed using hydrodesulphurization (HDS) in the #1 Diesel HDS Unit. In the process diesel is combined with hydrogen, heated to 500°F and passed over a catalyst bed to hydrogenate unsaturated chemical bonds and liberate sulfur and other impurities. Typically, organic sulfur compounds are converted to H₂S and organic nitrogen into NH₃. Removal of sulfur from the diesel allows further processing. The combustion sources at the #1 Diesel HDS include a charge heater and a stabilizer reboiler.

On March 31, 2006, the NWCAA issued OAC 949 approving a heater reliability project at the #1 Diesel HDS. The project was comprised of installing ultra-low NO_x burners on both the Charge Heater and Stabilizer Reboiler. The ULNB were installed in each and the unit restarted on May 20, 2006. As a condition of the OAC, a NO_x CEM was required on the Stabilizer Reboiler to enable BP to demonstrate NO_x reductions for the 2001 Consent Decree.

On July 1, 2009 the NWCAA issued revised OAC 949a. This revision added a requirement for a NO_x CEM on the #1 Diesel HDS Charge Heater to enable BP to demonstrate NO_x reductions from retrofitting with ULNB for the 2001 Consent Decree. Other OAC revisions included a modification to the requirements for source testing to allow testing at representative firing rates rather than at 70% of the Charge Heater maximum firing rate and above 90% of the Stabilizer Reboiler maximum firing rate. The OAC includes a condition to conduct additional source testing within 90 days if the 720-rolling average firing rate exceeds the firing rate recorded during the most recent test by more than 20%.

2. #2 Diesel HDS Unit

Construction of the #2 Diesel HDS Unit (#2 DHDS) was completed in 2006, with startup occurring on May 22, 2006. The #2 DHDS allows the refinery to produce low-sulfur (less than 0.05 wt%) over-the-road diesel. The unit consists of a 25 MMBtu/hour Charge Heater, a catalyst bed reactor section and a fractionation section. In the hydrotreating process sulfur is converted in the presence of a catalyst and hydrogen to H₂S which is sent to the Sulfur Recovery Unit. The #2 DHDS reduces the sulfur content of the produced diesel stream by approximately 5000 tons per year. The NWCAA issued OAC 892 on March 3, 2005, approving construction and operating of the #2 DHDS Unit.

On September 5, 2007, the NWCAA issued revised OAC 892a. This revision added a condition to limit the charge heater firing rate to 35 MMBtu/hour and reduced the firing rate under which the heater was to be source tested from 90% to 80%.

On January 28, 2009, the NWCAA issued revised OAC 892b. This revision included a modification to the requirements for source testing to allow testing the Charge Heater at representative firing rates rather than at 80% of its maximum firing rate. The OAC includes a

condition to conduct additional source testing within 90 days if the 720-rolling average firing rate exceeds, by more than 20%, the firing rate recorded during the most recent test.

3. #3 Diesel HDS Unit

The #3 Diesel Hydro-Desulfurization Unit (#3 DHDS) was approved by the NWCAA under OAC 1064 issued November 29, 2010 as part of the BP Clean Fuels Project. The Clean Fuels Project was also approved under PSD-10-01 issued by Ecology on December 13, 2010. The PSD permit addresses PM₁₀ as the only PSD- applicable pollutant for the project. PM_{2.5} was permitted as a minor pollutant because PSD applicability was based only on PM₁₀ at the time the application was being reviewed. PM_{2.5} became a PSD regulated pollutant only after EPA finalized the front and back half source test method for PM_{2.5}. This occurred in December 2010 after issuance of OAC 1064 for the Clean Fuels Project.

The Clean Fuels Project includes construction of the #2 Hydrogen Plant and #3 DHDS Unit. NOx emission increases that will result from the Clean Fuels Project are to be offset by retrofitting the Hydrocracker 1 Stage Fractionator Reboiler with ULNB. This offset project, approved by the NWCAA under OAC 1067 issued November 29, 2010, and revised as OAC 1067a on July 7, 2011, allowed the Clean Fuels Project to avoid PSD applicability for NOx.

The Clean Fuels Project will allow the refinery to produce ultra-low sulfur diesel fuel for the non-road market and to reduce the benzene content of gasoline. The #3 DHDS is scheduled for construction in 2011, with completion and startup anticipated in the fourth quarter of 2012. The primary emission unit at the unit is the #3 DHDS Charge Heater with a rated capacity of 28 MMBtu/hour HHV heat input. The heater will be equipped with ultra-low NOx burners (ULNB) to control emissions of NOx. The burner pilots will be fired with natural gas and the heater will combust refinery fuel gas from the existing main refinery mix drum. Although the heater will be designed with a maximum heat input capacity of 28 MMBtu/hour, this firing rate will only be required during startup because hydro-desulfurization is an exothermic process. The actual anticipated nominal firing rate for the heater during normal operations is estimated to be 12 MMBtu/hour. Other emissions at the #3 DHDS will be from equipment components (valves, flanges, pumps, compressors, connectors). Process equipment components in VOC or HAP service will be subject to the applicable requirements of NSPS 40 CFR 60 Subpart GGGa and NESHAP 40 CFR 63 Subpart CC. These federal programs require an enhanced LDAR program that is consistent with the existing program that the refinery implemented under past BACT determinations and under the 2001 BP Consent Decree. On May 1, 2013 the NWCAA received BP's compliance certification with the requirements of 40 CFR 60 Subpart GGGa for the clean fuels project.

OAC 1064a superseded OAC 1064 on March 13, 2014. After start-up of the units approved by OAC 1064, BP requested this revision to:

- address administrative changes
- remove inapplicable requirements dealing with construction and start-up
- remove stack velocity meter on #2 Hydrogen SMR stack and conduct Method 19 calculations instead (stack velocity meter was found to not track with process)
- remove velocity, Btu content, and Method 19Fd ongoing determination for #2 Hydrogen Flare

All new source review conditions contained in OAC 1064a and PSD-10-01 have been incorporated into the AOP, except as noted below.

- During permitting process the NWCAA served as the State Environmental Policy Act (SEPA) lead agency for the Clean Fuels Project. The SEPA review addressed all environmental impacts of the project including GHG emission increases. OAC 1064a includes a number of conditions that are considered "Mitigated Determination of Nonsignificance Terms and

Conditions". These conditions of approval were imposed pursuant to RCW 43.21C.060 and Sections 155.8 and 155.13 of the NWCAA Regulation. They are not considered new source review approval conditions issued under NWCAA Section 300, RCW 70.94.152, the federal Clean Air Act or the Washington State Implementation Plan. Therefore these SEPA- based mitigation terms and conditions are not considered "AOP applicable requirements" and are not included in the air operating permit.

- PSD-10-01 Condition 20 states that, "Requirements in the following approval conditions to notify or report to or acquire approval or agreement from Ecology and the Northwest Clean Air Agency may be satisfied by providing such notification, reporting, or approval request to NWCAA if the approval conditions of this PSD permit have been incorporated in BP's Title V permit (40 CFR Part 70)". Therefore, all PSD-10-01 conditions that require notification, reporting, or approval to Ecology now refers to the NWCAA because the PSD conditions have been incorporated into the AOP.
- PSD-10-01 Conditions 15 requires BP to provide initial notification of commencing construction and firing. These one-time notifications were received on 7/8/11 and 4/26/13. Since Condition 15 doesn't have any on-going requirements and the one-time requirements have been completed, this condition is not included in the AOP.
- PSD-10-01 Conditions 19 states that construction must begin with 18 months of receipt of the final PSD and must not be discontinued for a period of 18 or more months. The unit has been constructed. Therefore, this condition is now obsolete and is not included in the AOP.

3.7 Isomerization Unit

The Isomerization Unit is comprised of four sub-units: 1) the Naphtha Dehexanizer; 2) the Isomerization Hydrotreater (IHT); 3) the BenSat™ Unit; and the Penex™ (isomerization) Unit. The Isomerization Unit is used to improve octane quality and reduce benzene compounds in gasoline blending stocks. This is accomplished by saturating the incoming streams using hydrogen.

Construction History and Regulatory Applicability

Construction of the Isomerization Unit was part of an overall refinery project for improving the quality of gasoline produced by the BP Cherry Point Refinery. This "Clean Gasoline Project" was designed to process light naphtha feedstocks to produce a gasoline blend component that has only trace amounts of benzene, olefins or sulfur and a high octane value. The Clean Gasoline Project was completed in July 2004, allowing the refinery produce gasoline with very low sulfur and benzene content that could meet the 2005 federal gasoline standard.

The NWCAA issued OAC 814 on June 2, 2003, and Ecology issued PSD-02-04 on May 16, 2003, approving construction of the new Isomerization Unit and a new #5 Boiler. On March 24, 2004, the NWCAA issued revised OAC 814a. On April 20, 2005, Ecology issued PSD-02-04 Amendment 1 with revised conditions for the #5 Boiler. On July 9, 2012, the NWCAA issued revised OAC 814b. This OAC superseded both of the previous versions because OAC 814a did not explicitly supersede OAC 814. OAC 814b was issued to improve formatting and to clean up the order for better incorporation into the air operating permit.

The new Isomerization Unit started up on July 19, 2004. Shortly thereafter, the Merox Unit was decommissioned from service. The Merox Treater had previously been used for mercaptan extraction and sweetening (desulfurizing) of gasoline. The streams such as coker naphtha that were previously routed to this Merox Unit are now sent to the Isomerization Unit where they are converted to high quality gasoline blending components.

3.8 Light Ends and LPG Units

The Light Ends Unit (LEU) and Liquefied Petroleum Gas (LPG) Unit produce light hydrocarbon products for commercial or industrial sale. Commercial liquefied gas consists of propane, butane, and mixtures thereof. Other products can include methane for feed stocks to petrochemical plants and butanes for gasoline blending.

In general, the LEU processes feed streams by distillation to produce products that are used in gasoline blending or for direct sale. Similarly, the LPG Unit processes feed streams to produce products that are used for refinery fuel gas or for direct sales.

Feed streams to the LPG Unit consist of fuel gas from various refinery processes including crude distillation, catalytic reforming, steam cracking, and coking. The feed streams are compressed and routed through a deethanizer. Methane and ethane overheads are recovered and recycled as refinery fuel gas for use in heaters and boilers throughout the refinery. Bottoms from the deethanizer are routed through a depropanizer from which LPG and butanes are separated. The LPG is then processed to remove residual sulfur containing compounds, dried, and stored in pressure vessels for commercial sale. The butanes are further processed to separate isobutanes from normal butane in debutanizers and depentanizers. A fraction of the recovered butanes are used for blending with gasoline. The remaining butane is sold.

Major equipment at the LEU/LPG Unit pumps, valves, flanges, drains, and compressors along with the deethanizer, depropanizer, debutanizer, and depentanizers. This unit has a number of components in light liquid and gaseous service that can emit fugitive VOCs and HAPs.

Construction History and Regulatory Applicability

The LEU was built with the refinery in 1970. The LPG Unit was built later in 1987. One major project occurred at this unit that affected air emissions: the RVP Phasedown Project. The following is a discussion of the project.

1. RVP Phasedown Project

In 1990, the refinery proposed a project to lower the vapor pressure of gasoline as mandated by federal fuel requirements. The project was designed to reduce the maximum Reid vapor pressure (RVP) of gasoline from 10.5 psig to 9 psig during summer months. The objective of the project was to use less butane during gasoline and to ship the excess butane off site. The RVP Phasedown project consists converting three debutanizers, one in the Crude unit, one in the Hydrocracker Unit and, one in the #1 Reformer Unit, into depentanizers, construct new butane/pentane storage spheres, construct a new butane loading station, construct a new debutanizer tower at the Light Ends Unit (LEU). The project included an increase in the steam demand from the existing utility boilers. Emissions associated with the project included NO_x, SO₂, PM, and CO from the increased boiler load and VOC from the LEU modifications. The refinery proposed to offset all incremental emission increases related to the RVP Phasedown through other completed projects and retired accrued emission reduction credits of 81 tons/year of NO_x, 5 tons/year of SO₂, 2 tons/year of PM₁₀, 20 tons/year of VOC, and 2 tons/year of CO.

The NWCAA approved the project under OAC 298 issued December 4, 1990. On April 30, 2012, the NWCAA issued revised OAC 298a to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.9 Hydrogen Plant

There are a number of processes that are not directly involved in the production of hydrocarbon fuels but serve a supporting role. The Hydrogen Plant is one such unit. Refineries with extensive hydrotreating and hydrocracking operations require more hydrogen than that produced by their reforming units. At the date of AOP issuance, the refinery has one hydrogen

plant (#1 Hydrogen Plant) to produce hydrogen for the refinery. A second plant, the #2 Hydrogen Plant, was approved by the NWCAA in 2010 as part of the Clean Fuels Project. Both plants produce hydrogen gas based on the process of steam methane reforming of natural gas.

Construction History and Regulatory Applicability

1. #1 Hydrogen Plant

The #1 Hydrogen Plant was built during original refinery construction in 1970. To date, there have been no equipment modifications at the #1 Hydrogen Plant triggering NSR permitting, and therefore it is considered a "grandfathered" unit.

At the #1 Hydrogen Plant, hydrogen is produced in a four-step process involving; reforming, shift conversion, purification, and methanation. Reforming is a catalytic reaction of methane with steam at high temperatures to form CO, CO₂ and H₂. High temperatures are achieved by heating in the reforming furnaces. After reforming, additional steam is added in a shift conversion that liberates additional H₂ from the reaction of CO and H₂O. In the third step, CO and CO₂ are absorbed in beds and the remaining H₂ rich gas is separated and purified. In the final step, any remaining CO and CO₂ left in the H₂ rich gas stream is converted back to CH₄ using catalyst and temperatures in the range of 700°F to 800°F.

The main emission units at the #1 Hydrogen Plant are the North and South Reforming Furnaces. The plant has a number of equipment components in gaseous service that can emit fugitive VOCs and HAPs including valves, flanges, vents, sewer line connections and pressure relief devices. The #1 Hydrogen Plant produces a CO₂ rich gas stream that contains methanol, a federally listed HAP. A portion of this stream is routed to the adjacent PraxAir facility for further processing, and the remainder is normally vented to the atmosphere due to processing limitations at PraxAir. This is allowed since this process stream is exempted from the "Miscellaneous Process Vent Category" regulated under 40 CFR 63 Subpart CC (NESHAPS from Petroleum Refineries - §63.641) due to the low concentrations of methanol in the stream.

2. #2 Hydrogen Plant

The #2 Hydrogen Plant was approved by the NWCAA under OAC 1064 issued November 29, 2010 as part of the BP Clean Fuels Project. The Clean Fuels Project was also approved under PSD-10-01 issued by Ecology on December 13, 2010. The PSD permit addresses only PM₁₀ as the only PSD level pollutant for the project. The Clean Fuels Project includes construction of the #2 Hydrogen Plant and #3 DHDS Unit. NOx emission increases that will result from the Clean Fuels Project are to be offset by retrofitting the Hydrocracker 1 Stage Fractionator Reboiler with ULNB. This offset project, approved by the NWCAA under OAC 1067 issued November 29, 2010, and revised to OAC 1067a on July 29, 2011, allowed the Clean Fuels Project to avoid PSD applicability for NOx.

The Clean Fuels Project will allow the refinery to produce ultra-low sulfur diesel fuel for the non-road market and to reduce the benzene content of gasoline. The #2 Hydrogen Plant is scheduled for construction in 2011, with completion and startup anticipated in the fourth quarter of 2012. The plant is designed to produce 40 million standard cubic feet per day (MMSCFD) of hydrogen and purify an additional 4 MMSCFD of hydrogen from refinery off gas streams. The main emission units at the new hydrogen plant include the #2 Hydrogen Plant Steam Methane Reformer (SMR) Furnace and new #2 Hydrogen Plant Flare. The flare is designed to combust off-specification hydrogen during operations such as plant startups, shutdowns and malfunctions. Process components such as pumps and valves at the #2 Hydrogen Plant will be a source of process fugitives including CO, VOC and HAP.

Similar to the #1 Hydrogen Plant, the #2 Hydrogen Plant will produce hydrogen gas using a process of steam methane reforming of natural gas. Unlike the #1 Hydrogen Plant, the new plant will include a pressure swing adsorption (PSA) purification system. The PSA technology

will allow the #2 Hydrogen Plant to produce hydrogen that is higher purity what is produced at the #1 Hydrogen Plant. Feedstocks to the #2 Hydrogen Plant will include natural gas and certain high hydrogen content refinery off gas (ROG) streams. Process equipment at the #2 Hydrogen Plant will consist of feed knock out pots, feed conditioning reactors, a product compressor, a furnace, a hot shift reactor, PSA vessels, purge gas vessel, steam production equipment, motor control center, pipe racks and ancillary equipment.

Hydrogen is produced by reacting superheated steam with a source of light hydrocarbons in the presence of a nickel catalyst where most of the hydrocarbon is converted to CO₂ and H₂. Carbon monoxide (CO) is produced as a byproduct of the reaction. In second step of the process, CO and H₂O are converted to CO₂ and H₂ in the hot shift reactor which contains a catalyst. The hydrogen is then purified by separating it from the other gasses in a series of PSA vessels. These vessels contain an adsorbent that collects all gasses except hydrogen, which passes through. The gasses held in the PSA vessels are desorbed on a regularly scheduled basis. The desorbed gas is considered residue PSA off gas and is combusted as fuel in the SMR Furnace. The high purity hydrogen exiting the PSA vessels is compressed and distributed for use within the refinery.

The SMR Furnace has a nominal heat input capacity of 430 MMBtu/hour (HHV) during normal operation and a maximum designed heat input capacity of 496 MMBtu/hour. PSA residue gas is the primary source of fuel for the furnace with natural gas being supplemented when necessary. It is estimated that 90% of the heat input to the furnace will be from PSA residue gas and 10% from natural gas. The furnace will be equipped with ULNB and selective catalytic reduction (SCR) to control emissions of NO_x. Aqueous ammonia injected into the SCR will be supplied from the aqueous ammonia storage tanks that also serve the SCR system at the #6 & 7 Boilers. Because sulfur is harmful to the catalyst used to synthesize hydrogen, the #2 Hydrogen Plant will be equipped with sulfur guard beds that purify the incoming natural gas feedstock. The sulfur guard beds contain a catalyst that converts sulfur to hydrogen sulfide (H₂S) and downstream zinc oxide (ZnO) beds adsorb the H₂S. The sulfur guard beds will reduce the sulfur content of the natural gas feed to less than 0.1% ppm. The PSA residue gas used as fuel in the furnace has very low sulfur content.

The #2 Hydrogen Plant will be equipped with an elevated flare that will continuously combust small volumes (about 4,600 scf/hour) that is comprised of nitrogen purges from compressor seals and compressor distance piece vents, and natural gas as sweep gas to maintain a collection header free of oxygen. The flare is also designed to handle higher volumes associated with startup, shutdown and malfunction events. The flare will be attached to the SMR Furnace stack and will not be configured to handle material generated from any other refinery units. Natural gas is used to maintain a flame in the flare pilot burners.

The flare is subject to the requirements of 40 CFR 60 Subpart Ja, including the requirement to have and implement a flare management plan. BP provided a copy of the flare management plan to NWCAA on 3/19/13. The plan stated that the flare was in compliance at start-up.

The #2 Hydrogen Plant will produce steam to support the SMR reforming reaction. The hydrogen plant also has the capacity to produce 140,000 lb/hour of excess steam. This excess steam will be routed to the refinery's common steam header as utility steam to support other refinery processes.

Fugitive emissions at the #2 Hydrogen Plant will be from process equipment (valves, flanges, pumps, compressors, connectors). Process equipment components in VOC or HAP service will be subject to the applicable requirements of NSPS 40 CFR 60 Subpart GGGa and NESHAP 40 CFR 63 Subpart CC. These federal programs require an enhanced LDAR program that is consistent with the existing program that the refinery implemented under past BACT determinations and under the 2001 BP Consent Decree. On May 1, 2013 the NWCAA received BP's compliance certification with the requirements of 40 CFR 60 Subpart GGGa for the clean fuels project.

OAC 1064a superseded OAC 1064 on 3/13/14. After start-up of the units approved by OAC 1064, BP requested this revision to:

- address administrative changes
- remove inapplicable requirements dealing with construction and start-up
- remove stack velocity meter on #2 Hydrogen SMR stack and conduct Method 19 calculations instead (stack velocity meter was found to not track with process)
- remove velocity, Btu content, and Method 19Fd ongoing determination for #2 Hydrogen Flare

All new source review conditions contained in OAC 1064a and PSD-10-01 have been incorporated into the AOP, except as noted below.

- During permitting process the NWCAA served as the State Environmental Policy Act (SEPA) lead agency for the Clean Fuels Project. The SEPA review addressed all environmental impacts of the project including GHG emission increases. OAC 1064a includes a number of conditions that are considered "Mitigated Determination of Nonsignificance Terms and Conditions". These conditions of approval were imposed pursuant to RCW 43.21C.060 and Sections 155.8 and 155.13 of the NWCAA Regulation. They are not considered new source review approval conditions issued under NWCAA Section 300, RCW 70.94.152, the federal Clean Air Act or the Washington State Implementation Plan. Therefore these SEPA based mitigation terms and conditions are not considered "AOP applicable requirements" and are not included in the air operating permit.
- PSD-10-01 Condition 20 states that, "Requirements in the following approval conditions to notify or report to or acquire approval or agreement from Ecology and the Northwest Clean Air Agency may be satisfied by providing such notification, reporting, or approval request to NWCAA if the approval conditions of this PSD permit have been incorporated in BP's Title V permit (40 CFR Part 70)". Therefore, all PSD-10-01 conditions that require notification, reporting, or approval to Ecology now refers to the NWCAA because the PSD conditions have been incorporated into the AOP.
- PSD-10-01 Conditions 15 requires BP to provide initial notification of commencing construction and firing. These one-time notifications were received on 7/8/11 and 4/26/13. Since Condition 15 doesn't have any on-going requirements and the one-time requirements have been completed, this condition is not included in the AOP.
- PSD-10-01 Conditions 19 states that construction must begin with 18 months of receipt of the final PSD and must not be discontinued for a period of 18 or more months. The unit has been constructed. Therefore, this condition is now obsolete and is not included in the AOP.
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3.10 Calciners and Coke Storage & Handling

Petroleum coke calcining is a process used to convert "green coke" produced at the Delayed Coker into a more valuable "needle coke" or "calcined coke" product by exposing the material to sustained high temperatures in a rotating calciner hearth. The calcining process drives off sulfur and volatile organic compounds. The calcined coke produced at the Cherry Point Refinery is considered anode-grade quality due to its low metals content.

The #1, 2 & 3 Calciners are located adjacent to the Delayed Coker unit. Green coke produced at the coker is transferred by covered belt conveyor to raw (green) coke feeding bins where they are fed to one of the three calciner kilns. In the calciner, green coke is heated to temperatures between 2400° F and 2700° F in a rotary hearth type kiln. The calcined coke leaves the kiln and goes through a transfer chute to a water spray cooler. The cooled coke is then conveyed by covered belt conveyor to the calcined coke storage barns where it is stored

until it is loaded into railcars or trucks. The refinery also has the equipment to unload green coke from railcars or to load green coke into railcars or trucks. Waste heat from the coke calcining process is recovered and used to generate steam for the refinery. When not calcining coke, supplemental firing of the heat recovery steam generators can be accomplished with refinery fuel gas. Also, the Calciner treats wastewater API-recovered slop oils as well as recovered coke and coke fines.

Flue gasses from calcining operations are routed to one of two stacks. The flue gasses from the #1 & #2 Calciners are routed through Stack #1 and flue gasses from the #3 Calciner are routed through Stack #2. Air pollutants emitted from the calciners include products of combustion such as PM, NO_x, CO, VOC, and SO₂. Because of the high sulfur content of the green coke, the calciners emit relatively large amounts of SO₂ at the refinery as sulfur is thermally driven off in the hearths. The calciners are also a significant source of fine particulate emissions at the refinery.

Major equipment in the calciner area include green coke crushers and storage barn, conveyor systems, calcining hearths, calcined coke silos, green coke and calcined coke loadout. Major emissions control equipment on the #1 & #2 Calciners (Stack #1) include caustic scrubbers followed by wet electrostatic precipitators (WESP). There are also numerous baghouses to control fugitive emissions from calcined coke transfer and storage operations.

The caustic scrubbers are used to control SO₂ emissions from the calciner stacks and the WESPs are used to control PM-10 and H₂SO₄ emissions. In some cases the refinery will shut down one or more cells in a WESP for maintenance or safety reasons. With a reduced number of cells operating, the refinery can continue to meet emission limits, but may need to reduce calciner production rates accordingly. The refinery monitors the secondary voltage and secondary amperage of each WESP according to approved WESP monitoring plans. In general, the cells are operated at a minimum secondary voltage of 35 kV and minimum secondary amperage of 300 mA to maintain compliance with permitted PM and H₂SO₄ limits. In addition, the #3 Calciner (Stack #2) is required to meet a minimum Specific Collection Area (SCA) of 126 ft² per 1,000 acfm stack flow as required by OAC 985a.

Construction History and Regulatory Applicability

The history of construction approvals and associated regulatory orders for the calciners is long and complex, spanning from 1977 to the present. The #1 & #2 Calciners were constructed in 1977, and the #3 Calciner was constructed in 1985. Devices associated with controlling emissions from these calciner hearths have changed over the years in response to challenges in meeting PM and opacity limits.

1. #1 & #2 Calciners

The #1 & #2 Calciners were constructed in 1977 and have a long history of compliance and permitting related activities. The table below summarizes these agency actions provides a basis for whether or not particular orders are incorporated into the air operating permit.

Table 3-1: #1 & #2 Calciner Permitting and Approval History

#1 & #2 Calciner (Stack #1)			
Order	Date	In AOP?	Description/Comments
OAC 211c	Issued 10/12/1977 Revised 11/17/1977 Revised 12/14/1977 Revised 9/18/12	Yes	Approval to construct the #1 & #2 Calciner with no specific emission limits on the Calciner stack. Instead the approval includes the following refinery-wide limits. <ul style="list-style-type: none"> • PM 60 ton/month • SO₂ 2,354 lb/hour, monthly average
NWCAA Regulatory Order "PM Bubble"	Issued 06/13/1984	No, superseded by OAC 689b issued September 18, 2012	Issued in response to ongoing compliance problems at the Calciner. The order limits: <ul style="list-style-type: none"> • PM 60 ton/31-day month for the entire refinery • PM 50.5 ton/31-day month "bubble" for the #1 & #2 Calciner, Crude Heater, South Vacuum Heaters, North and South Coker Heaters and #1 Boiler. • Calcined coke production rate limited to 60 ton/hour.
NWCAA Regulatory Order "Opacity"	Issued 11/30/1984	No, superseded by Regulatory Order 11	RO issued in response to ongoing opacity exceedances. The order allowed up to 40% opacity until tube replacement in recuperators was complete and visual observations demonstrated that calciner was back into compliance with the 20% opacity SIP limit.
Emission Reduction Credit 14	Issued 10/13/1993	No, this ERC expired after 10 years	NWCAA granted an SO ₂ ERC of 1548 tons from the voluntary installation of a Dynawave Scrubber on the #1 & #2 Calciners. The ERC set a 40 lb/hr SO ₂ limit on the stack.
NWCAA Regulatory Order 011	Issued 05/23/1995	No, this RO was voided per OAC 660 following installation of the WESP and visual emissions data confirming compliance.	In lieu of continuous opacity monitoring, the RO required monitoring the oxygen concentration in the radiant section of the hearths and semi-monthly visual emission observations.
OAC 660a	Issued 12/07/98 Revised 9/18/12	Yes	Replacement of a portion of the Dynawave Scrubber with a wet electrostatic precipitator (WESP).
OAC 689b	Issued 04/13/1999 Revised 10/27/2008 Revised 9/18/12	Yes	As part of the Coker debottlenecking effort, increase the average coke processing rate in the Calciner from 28 ton/hr to 38 ton/hr. Establish opacity, PM ₁₀ , NO _x , SO ₂ , and H ₂ SO ₄ emission limits, and a SO ₂ netting offset from H ₂ S scrubbing of the Vacuum Tail Gas.

The #1 & #2 Calciners, constructed in 1977, were approved under OAC 211, which established refinery-wide PM and SO₂ emission limits. These limits were based on the emission estimations that the refinery provided as part of their Notice of Construction application. There were no specific BACT limits placed on emissions from the #1 & #2 Calciners (Stack #1). However, the stack still had to meet general requirements for sources under applicable SIP rules, such as grain load standards for combustion devices and 20% opacity limits set forth in the WAC-173-400 and NWCAA Regulation.

After construction of the #1 & #2 Calciners, it became clear that controlling visual emissions from the stack to 20% opacity was going to be difficult due to a characteristic blue haze forming in the plume. The Calciner was also having challenges meeting grain loading limits. The refinery attempted to minimize opacity and particulate emissions by controlling various operating parameters including increasing excess oxygen levels in the hearths. These methods proved unsuccessful and on June 13, 1984, the NWCAA issued the Particulate Bubble Regulatory Order. The order allowed the #1 & 2 Calciners to increase particulate emissions above 46.8 tons per month with a commensurate reduction in emissions at four refinery heaters (Crude, South Vacuum, and North & South Delayed Coker Heaters) and one utility boiler (#1 Boiler that has since been decommissioned) by curtailing the amount of fuel oil burned in the heaters and boiler. The order set a 50.5 ton per month particulate "bubble" on the four heaters, one boiler and #1 & 2 Calciner stack. The Order also included a refinery-wide particulate limit of 60 tons per month and established a production rate limit on the #1 & 2 Calciner of 60 tons per hour.

September 18, 2012, as part of a comprehensive effort to clean up existing orders prior to incorporation into the AOP, the NWCAA issued OAC 689b. OAC 689b superseded the Particulate Bubble Regulatory Order because the reasons for order were no longer germane to the equipment and operating scenarios at the refinery, nor was it consistent with construction approvals issued for the #1 & 2 Calciners after 1984.

On November 30, 1984, the NWCAA issued an "Opacity" Regulatory Order allowing opacity from the #1 & #2 Calciners to exceed the 20% opacity limit of the NWCAA regulation, up to 40% until the tubes in the recuperators were replaced. This opacity improvement project was completed within one year and visual emissions observations demonstrated that the Calciners were back into compliance with the 20% limit. Demonstration of compliance by certified opacity readings conducted by the refinery effectively voided the "Opacity" Regulatory Order, as specified in the order.

A state-of-the art flue gas desulfurization device called the Dynawave Scrubber was installed on the #1 & #2 Calciners and tested in phases from 1988 to 1993 with the aim of further controlling opacity and SO₂ emissions. Because the project was considered voluntary, no construction approval was required by the NWCAA. The Dynawave Scrubber made a significant reduction in SO₂ emissions and on October 13, 1993, the NWCAA issued Emission Reduction Credit 14 (ERC 14) crediting the refinery with a 1,548 ton per year SO₂ reduction from the project. To ensure that SO₂ emissions remained at expected levels, the ERC 14 established SO₂ emission limits of 40 lb per hour and 175 ton per year for the #1 & #2 Calciner stack.

The NWCAA issued Emission Reduction Credit 14 (ERC 14) expired October 13, 2003, ten years after issuance. There is no indication that this ERC was ever utilized to net out of Prevention of Significant Deterioration (PSD) major source permitting. If the SO₂ credits had been utilized, the SO₂ limits established in ERC 14 would have been reestablished in another federally enforceable order, presumably an OAC issued for the PSD netted project. In this particulate case, there is no record to substantiate that the emission reduction credits were ever utilized, sold or otherwise activated.

WAC 173-400-136 Use of Emission Reduction Credits (ERC).

(5) Redemption period. An unused ERC expires ten years after date of original issue

Emission Reduction Credit 14's expiration on October 13, 1993, was documented in a NWCAA memo to the file dated July 20, 2012. Because ERC 14 has expired, it is not cited in the air operating permit as an applicable requirement.

On May 23, 1995, the NWCAA issued Regulatory Order 011 granting the refinery permission to monitor the average oxygen concentration in the radiant section of the #1 & #2 Calciner hearths in lieu of continuously monitoring opacity in the stack. The order established a 4.0% daily average oxygen limit. On December 7, 1998, the NWCAA issued OAC 660 approving replacement of a portion of the Dynawave Scrubber with a wet electrostatic precipitator (WESP). The WESP was designed to control particulate matter and sulfuric acid mist (H_2SO_4) from the #1 & #2 Calciner stack. In addition, the OAC included limits for SO_2 and opacity. The WESP control device is based on the principal of imparting an electrical charge to aerosols and solids (together referred to as particulates) suspended in the WESP inlet gas stream. Once polarized or charged, the particulates are drawn out of gas stream to an electrode through electrical attraction. A water flushing system periodically removes acid mist and particulates that adhere to collection plates.

The WESP was installed and commenced operation on June 13, 1999. On January 3, 2000, the refinery submitted data demonstrating compliance with Condition 4 of OAC 660 limiting opacity from the #1 & #2 Calciner stack to 20% as measured by Ecology Method 9B. As a result, Regulatory Order 011 was effectively voided and the refinery was no longer required to assure a minimum 4.0% oxygen level in the hearths.

In 1999, as part of a Delayed Coker debottlenecking project, the refinery proposed increasing the calcined coke production rate from 28 tons to 38 tons per hour for each of the #1 & #2 Calciner hearths. The NWCAA approved this project on April 13, 1999 under OAC 689. The increased coke calcining rate required an increase in the heating load of the #1 & #2 Calciner hearths and project emissions included increases in NO_x , CO, SO_2 , PM, and VOC. Of these pollutants, NO_x and SO_2 were found to potentially exceed PSD thresholds, so the refinery modified the project to include a retrofit of the South Vacuum Heater with low- NO_x burners. The refinery also proposed to offset potential increases in SO_2 emissions by installing a DEA scrubber on the Vacuum Tail-Gas overhead fuel gas stream. As a result, all net emission increases from the project were determined to be below significant PSD thresholds.

In developing the emission limits for OAC 689, the NWCAA took into consideration approval of the WESP under OAC 660, PSD thresholds for PM_{10} and H_2SO_4 , and BACT requirements. OAC 689 also stated that the modified #1 & #2 Calciners are subject to applicable requirements of 40 CFR 60 Subparts GGG and QQQ, and 40 CFR 63 Subpart CC. On October 27, 2008, the NWCAA issued revised OAC 689a to restructure limits applicable to the North and South Coker Charge Heaters; however, no changes were made to conditions applicable to the #1 & #2 Calciners.

On September 18, 2012, the NWCAA issued revisions OAC 600a and OAC 689b. These revisions were made to clarify the requirements and clean up the orders prior to incorporation into the air operating permit.

2. #3 Calciner

On September 27, 1984, an application was submitted for construction of the #3 Calciner. This new calciner was designed to double the calcining capacity at the refinery with the addition of a single new rotary hearth. The project also included additional conveyors and silos for calcined coke handling controlled by a set of baghouses. Emission controls from calciner hearths include two-stage combustion for NO_x , a wet soda ash scrubber for SO_2 , and a WESP for PM and H_2SO_4 . Waste heat from flue gas is captured in a heat recovery steam generator, and steam can be generated with the calciner down through supplemental firing on refinery fuel gas.

The table below summarizes the permitting and approval history for the #3 Calciner and provides a basis for whether or not these orders are incorporated into the air operating permit.

Table 3-2: #3 Calciner Permitting and Approval History

#3 Calciner (Stack #2)			
Order	Date	In AOP?	Description/Comments
OAC 299	Issued 12/19/1984	No, the OAC is narrative only and contains no specific conditions.	Approve construction of the #3 Calciner controlled by a caustic scrubber and WESP.
PSD-3	Issued 12/20/1984	No, superseded by PSD-89-2	Approve construction of the #3 Calciner and caustic scrubber and WESP control equipment. Includes emission limits for opacity, PM, SO ₂ and NO _x . It also includes refinery-wide limits for PM and SO ₂ .
PSD-89-2	Issued 01/30/1989	Yes	Same conditions as PSD-3 except that the NO _x limit increased from 373 to 509 tpy, and refinery-wide PM and SO ₂ limits were removed.
PSD-95-01	Issued 03/14/1995 Amended 01/23/09	Yes	Established H ₂ SO ₄ limit for the #3 Calciner that was inadvertently left out of PSD-89-2.
NWCAA RO 018	Issued 06/30/1998	No, superseded by OAC 985	Requires an alternative monitoring plan for H ₂ SO ₄ control during times when the #3 Calciner is operated outside the conditions established in the, "Third Hearth Monitoring Plan, Sulfuric Acid Removal" dated August 16, 1995. Ongoing parameter monitoring required.
OAC 985	Issued 3/6/2007	Yes	Sets PM ₁₀ and H ₂ SO ₄ limits with ongoing compliance based on monitoring the Specific Collection Area of the WESP

On December 20, 1984, Ecology issued PSD-3 approving construction of the #3 Calciner. This PSD permit addressed the following PSD level pollutants; NO_x, SO₂, and TSP with estimated PTE at 373, 504, and 26 tons per year, respectively. The #3 Calciner was built and initial source testing conducted in April 1987. Information gathered during the source test identified an error in the flue gas NO_x concentration value used in the PSD application. As a result, the refinery requested to increase NO_x limit in PSD-3 from 373 to 509 tons per year. No change in the design or operation of the calciner was proposed. Ecology agreed and stated that the refinery still met BACT with the increase in NO_x emissions. On January 30, 1989, Ecology issued PSD-89-2 approving the higher NO_x limit and superseding PSD-3. Aside from the higher NO_x limit, PSD-89-2 was similar to the PSD-3, with one exception. It did not include the refinery-wide emission limits for PM and SO₂ that were included in PSD-3. On March 9, 1995, the NWCAA issued a letter to the refinery stating that the refinery-wide SO₂ and PM limits of PSD-3 were still valid even though PSD-3 was superseded by PSD-89-2, because Ecology had inadvertently omitted these limits when writing PSD-89-2. However in 2012 during the AOP renewal process, the NWCAA determined that the March 9, 1984 interpretation letter regarding the refinery-wide PM and SO₂ limits was not legally binding because PSD-89-2 explicitly supersedes all conditions

set forth in PSD-3. For this reason, the refinery-wide PM and SO₂ limits of PSD-3 are no longer listed in the air operating permit.

The refinery proposed to demonstrate compliance with the 90% SO₂ removal condition of PSD 89-2 by analyzing green coke sulfur and calculating a four week rolling average. The scrubber inlet SO₂ concentration was then calculated from the four week average and the scrubber efficiency calculated from the inlet and outlet concentrations.

On May 20, 1994 the refinery stated that the performance test on the #3 Calciner indicated that the PSD threshold for acid mist (H₂SO₄) could be exceeded. The refinery requested the Ecology amend PSD-89-2 as a result. The PSD application for the amendment indicated that the current BACT employed at the #1 & #2 Calciner was considered current BACT for controlling sulfur compounds from the #3 Calciner including H₂SO₄. On March 14, 1995, Ecology issued PSD-95-01 that exclusively limited H₂SO₄ emissions. PSD-95-01 did not supersede PSD-89-2; therefore, both permits remain in effect.

PSD-95-01 includes a requirement for the refinery to develop a monitoring plan to be approved by Ecology to demonstrate ongoing compliance with the H₂SO₄ limit. The *Third Hearth Monitoring Plan* was developed and approved by Ecology on October 17, 1995. Elements of this plan include;

- Measuring the secondary voltage and current on the WESPs. The hearth will be in compliance when at least 4 WESP cells are operating with a secondary voltage greater than 50 kV DC and a secondary current greater than 50 milliamps DC and the Calciner is not in startup, shutdown, or hot standby. Operation at secondary voltages less than 50 kV DC and/or secondary current less than 50 milliamps DC while the Calciner is in startup, shutdown, or hot standby mode are deemed to be in compliance.
- The averaging period is 24-hours
- After a turnaround (approximately every two years) the integrity of the WESP units will be determined by running an Air Load Test on each of the units.
- The WESP is on a scheduled cycle for flushing all six cells of approximately 72 hours.
- Monthly reports are provided to NWCAA on WESP operation including operating times; dates and time when the secondary voltage or secondary current was not collected when the unit was operating normally; an explanation of periods when the WESP secondary voltage and/or secondary current were below compliance requirements when not in startup, shutdown or hot standby; and any time periods and explanation as to why when fewer than 4 WESP cells were operating at compliance requirements.

On June 30, 1998, the NWCAA issued Regulatory Order 018 (RO 018) establishing an alternative means of demonstrating compliance with PSD-95-01 Condition 1. The Order required the refinery to modify their monitoring plan to include alternative operating conditions, conduct an emissions test according to the revised plan, determine operating conditions that correlate with compliance with PSD-95-01 Condition 1, and update the *Third Hearth Monitoring Plan* to reflect the changes in conditions of operating the WESP at a lower secondary voltage of 40 kV. The refinery performed a compliance test at the 40 kV secondary voltage condition and determined that PSD-95-01 Condition 3 was met with 4 or more WESP cells operating. The NWCAA and Ecology approved the revised monitoring plan on August 26, 1998.

In 1999 during routine maintenance the refinery determined that the lead tubes in the WESP were stretching and cracking, allowing acid gasses to attack the supporting structure of the lead tubes. One of the six WESP cells was so damaged that it required replacement. New special steel alloy was found to be available since the construction of the original WESP that allowed service in an acidic environmental thereby reducing long-term maintenance. This new WESP design was used to successfully replace the Dynaware scrubber on the #1 & #2 Calciner in 1999. The proposed new WESP for the #3 Calciner was designed with twice the collection

surface area (CSA) of the original #3 Calciner WESP. The new designed was comprised of 238 hexagonal tubes, whereas, the original WESP consists of 98 lead tubes.

Because the new WESP required different operating conditions than the old WESP the *Third Hearth Monitoring Plan* was revised accordingly. The revised plan decreased the minimum secondary voltage to 35 kV and minimum secondary amperage to 300 milliamps to ensure ongoing compliance during normal #3 Calciner operations. In June 2000, the refinery again revised the *Third Hearth Monitoring Plan* to reflect changes to the ductwork designed to distribute more of the flue-gas through the WESP cell #4 and better utilize its large collection surface area. The collection surface area of cells 1, 2, 3, 5, & 6 is 4,362 ft², whereas, cell 4 has a surface area of 10,928 ft². Because of the increased surface area of cell #4 the refinery eliminated cell #1. A revised *Third Hearth Monitoring Plan* was finalized on January 4, 2001, and the NWCAA and Ecology approved the revised plan on January 19, 2001.

On March 6, 2007, the NWCAA issued OAC 985 for a cell replacement project for the #3 Calciner WESP. The project involved replacing the four existing cells (2, 3, 5 and 6) with two larger cells. The cells were replaced due to erosion problems with the lead tube sheets. On October 27, 2008, the NWCAA issued revised OAC 985a to allow the use of an alternative test method for H₂SO₄ with advanced approval from the NWCAA. It was anticipated that the refinery would request the use of EPA Conditional Test Method 013 (CTM-013) in the future instead of Method 8 which is specified in the OAC. This OAC revision removed Condition 2 based confirmation from Dee Morse of the National Park Service that BP had satisfied this condition. On January 23, 2009, Ecology issued PSD 95-01, Amendment 1 allowing the #3 Calciner to be tested for H₂SO₄ emissions using either EPA test Method 8 or CTM-013.

Both PSD-95-01 and OAC 985a state the concentration based H₂SO₄ limit as 50 mg/m³. However, the limit in the air operating permit is stated as 50 mg/dscm (dry standard cubic meter – 0°C and 1 atmosphere) consistent with EPA Method 8.

3. Coke Handling and Storage

Table 3-3 Coke Storage & Handling Permitting and Approval History

Coke Storage & Handling			
Order	Date	In AOP?	Description/Comments
OAC 246	Issued 04/10/1980	No, the OAC is narrative only and contains no specific conditions.	Installation of a baghouse for calcined coke handling.
OAC 263	Approved 01/13/1982	No, there is no OAC. Instead the approval is narrative only as found in the minutes of the NWCAA Board meeting.	Installation of a baghouse to control PM during handling of calcined coke.
OAC 299	Issued 12/19/1984	No, the OAC is narrative only and contains no specific conditions.	Construct the #3 Calciner including calcined coke handling equipment controlled by baghouses.
OAC 293	Issued 9/13/1984	No, the OAC is narrative only and contains no specific conditions.	Installation of two additional calcined coke storage silos equipped with dust control.
OAC 306	Issued 11/14/1984	No, the OAC is narrative only and contains no specific conditions.	Installation of a coke dust loadout facility.

Coke Storage & Handling			
Order	Date	In AOP?	Description/Comments
PSD-3	Issued 12/20/1984	No, superseded by PSD-89-2.	New silo, railcar loadout, and #3 Calciner transfer tower limited to 20% opacity, 0.01 gr/dscf and 21 tpy.
PSD-89-2	Issued 1/30/1989	Yes	Opacity and PM limits carried over from PSD-3.
Ecology Order of Discontinuance of Permit Violation, PSD-3/PSD-89-2	Issued 08/24/2001	No, April 28, 2002 letter from Ecology states that the conditions of the order have been satisfied.	Required control of SO ₂ emissions from baghouses handling coke.

After the construction of the original Calciner and Coker, the refinery discovered that during the “debugging” phase of the project there was a dust collection problem and the original system, without revision, would not be able to fully recover dust that was emitted as part of the conveyance and handling of green and calcined coke. On March 1980, the refinery proposed to install 4 additional baghouses (approximately 2,500 cfm at 6-inches water gauge), one on top of each silo. The NWCAA issued OAC 246 in April 1980. OAC 246 required that the refinery install magnehelic gauges to measure the pressure drop across the bags. However, this OAC was considered narrative only, and therefore has not been included in the AOP.

On December 7, 1981 the refinery proposed constructing an additional baghouse (6,400 cfm) to improve the recovery of dust from transferring calcined coke. On April 23, 1982, the NWCAA Board of Directors approved the project as documented in the board minutes. The project was assigned NOC 263; however, there is no record of an approval letter being issued by the NWCAA in this matter. The NWCAA approval at the board meeting did not include any specific requirements for the project; therefore, there is no reference to this approval in the air operating permit.

The refinery continued its efforts to reduce particulate matter emissions from coke and calcined coke handling and in 1983 proposed to install a number of various baghouses at the calciner area to control dust. These included additional hearth area baghouses, silo baghouses, and calcined coke rail loading baghouses. The design included a pneumatic system to convey calcined coke dust to a new coke dust silo located north of green coke crusher and rail loading facility. The transfer system and silo is equipped with a bin vent (with filter bag) to control particulate emissions. The loadout system is designed to minimize dust being emitted to the atmosphere by the application of a slight vacuum on the loading hood and silo. On November 14, 1984, the NWCAA issued OAC 306 approving this calciner coke dust loadout facility project. OAC 306 is considered narrative and contains no requirements; therefore, this OAC is not referenced in the air operating permit.

On August 8, 1984, the refinery proposed to install two additional storage silos to increase the storage of calcined coke and minimize rail service disruptions. Emissions from the silos would be total suspended particulates. One baghouse would be installed to control PM emissions from the two new silos. The baghouse would have a nominal 10,000 cfm capacity with a 6 to 8: 1 cloth ratio. On September 13, 1986, the NWCAA issued OAC 293 approving this project. However, because OAC 293 is considered narrative with no specific requirements; it is not referenced in the air operating permit.

As discussed above the refinery proposed to expand their coke calciner capacity with the construction of the #3 Calciner in 1984 (PSD-3, PSD-89-2, PSD-95-01). This allowed the refinery to convert nearly all of its green coke feedstock to a finished calcined coke product. The approval of the #3 calciner also included additional baghouses, expanded material handling

capacity and storage silos. To control fugitive dust emission from the additional conveyance system and storage silos, the refinery proposed to install three new baghouses. According to the proposal these baghouses would be used in continuous operation to control fugitive dust emissions at coke transfer points. The conveyance systems and storage area would be covered. The baghouses are subject to the conditions of PSD 98-2 and PSD-95-01.

In 1988, the refinery proposed the construction of two new baghouses (5,800 cfm each) installed in conjunction with an existing baghouse (2,800 cfm) at the calcined coke loadout facility to control dust and particulate emissions. On December 19, 1988, the NWCAA issued a letter stating that the installation of these two additional baghouses does not require a Notice of Construction approval. The letter includes conditions; however, because it is not an Order of Approval to Construct (OAC), it is not considered a legally enforceable document and is therefore not referenced in the air operating permit.

Finally, on April 9, 2000, the refinery notified Ecology that a source of SO₂ emissions had been discovered at the refinery that was not anticipated when the Calciners were constructed and permitted. Emissions of SO₂ had been discovered at the stack of the baghouses for the #1, 2, & 3 Calciners. Baghouses are designed to control particulates and not gaseous pollutants such as SO₂. As a result, the refinery proposed to install BACT to control these emissions. On August 24, 2001, the Ecology issued an Order of Discontinuance of Permit Violation for PSD-3. Conditions of this Order are:

Condition 1: The refinery shall complete the necessary construction modification to collect all SO₂ emissions from the #3 Calciner and route them to the flue gas duct upstream of the wet scrubber by not later than December 31, 2001.

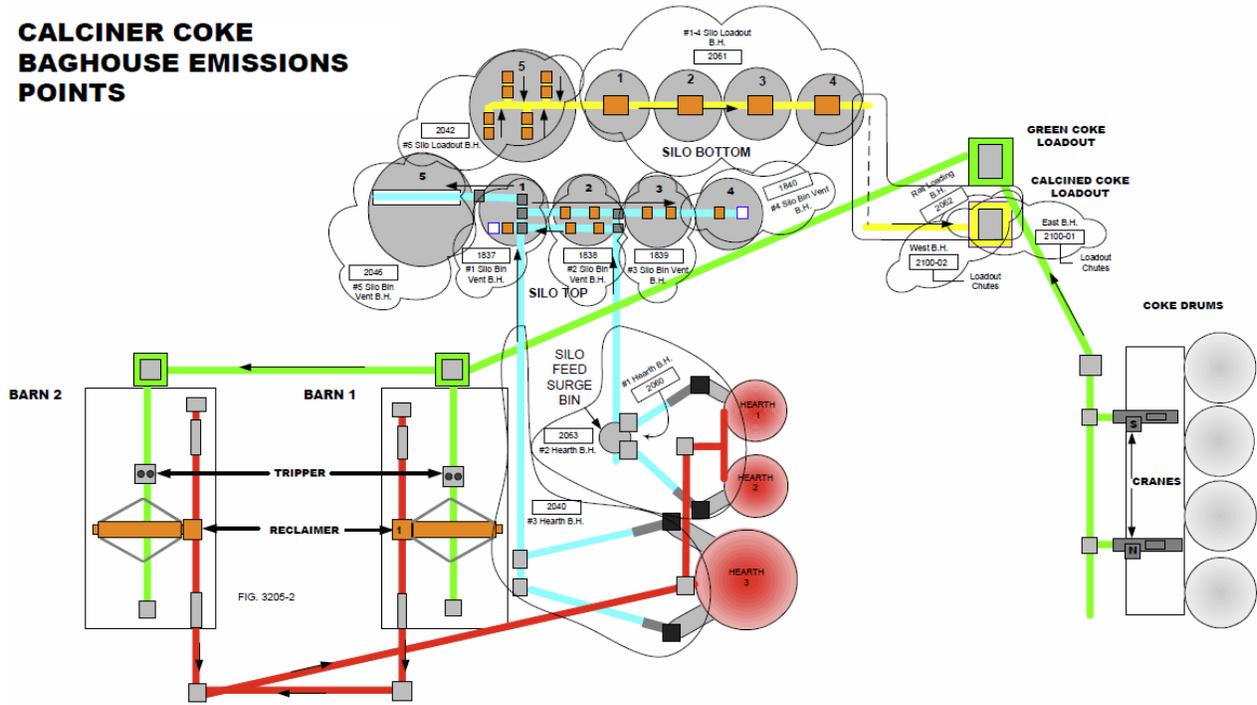
Condition 2: Ecology or designated representative will inspect the modification within 60 days after completion.

The refinery proposed to follow the same approach to controlling SO₂ emission from #1 & #2 Calciners.

Construction of the collection system for the #3 Calciner was completed on December 21, 2001. The Ecology requested that a representative of the NWCAA perform the visual inspection in accordance with the Order of Discontinuance. On June 23, 2002 the refinery completed installation of BACT on #1 & #2 Calciners. For #1, 2 & 3 Calciners the gas streams from the baghouses are routed to waste heat recovery system induced draft fans where SO₂ is removed in the existing caustic scrubber. On October 24, 2002, a representative of NWCAA performed a visual inspection and confirmed the changes.

The figure below shows particulate emission points and their associated control devices located within the calcined coke handling area. The conveyors and silo feed surge bin are controlled by routing fugitive emissions back to the calciner hearths. The silos are controlled using baghouses (B.H.) located on silo bin vents. The calcined coke loadout to railcars is controlled by the East and West baghouses. Relative to calcined coke, green coke is comprised of larger particles and contains enough moisture to minimize the release of fugitive emissions when handling. Therefore, green coke storage & handing does not require specific emission control equipment.

**CALCINER COKE
 BAGHOUSE EMISSIONS
 POINTS**



3.11 Boilers and Cooling Towers

Steam utility boilers and cooling towers are located within the Utility Area. There are two cooling towers at the refinery. These are non-contact cooling towers and as such hydrocarbon streams do not directly contact the cooling water. Instead non-contact heat exchangers are used to remove heat from hydrocarbon products. The cooling towers can be a source of VOC emissions to the atmosphere if leaks develop in cooling water heat exchangers or condensers.

Boilers produce steam that is used throughout the refinery for a wide variety of purposes including power for driving steam turbines, pumps, and compressors. Other examples of steam use at the refinery include heating of storage tanks with steam coils, increasing the temperature of hydrocarbon process streams with heat exchangers and for steam heat tracing of piping.

All boilers are located in the boilerhouse and burn refinery fuel gas and/or natural gas. Emissions from the boilers are from products of combustion including PM₁₀, SO₂, CO, NO_x, VOC and HAP.

Construction History and Regulatory Applicability

#1, 2 & 3 Boilers were constructed during original refinery construction in 1970. All three of these boilers have been replaced over time with the construction of the #4 Boiler in 1991, #5 Boiler in 2004, and #6 & 7 Boilers in 2008. The #2 Boiler was decommissioned in 2003, and the #1 & 3 Boilers were decommissioned in 2009.

The #1 Cooling Tower was constructed during original refinery construction in 1970. The #1 Cooling Tower is still in operation. Additional cooling capacity was added with construction of the #2 Cooling Tower in 1990.

1. #4 Boiler

On January 14, 1992 the NWCAA issued OAC 351 approving construction of the #4 Boiler at the refinery to supply steam in support of the RVP Phasedown project. The #4 Boiler has the

capacity to produce 150,000 lb/hour of 600 psi steam, and a heat input capacity of 216 MMBtu HHV/hour. During permitting BACT was determined to be the use of gaseous fuel, low-NOx burners and induced flue gas recirculation. This approval order has been revised five times to its current version OAC 351e. Below is a summary of each revision.

Revision a (June 4, 1993): Eliminated requirement on maximum steam production and testing requirements for PM10, VOC's, and SO2.

Revision b (April 11, 1994): Due to results of source emission test results for NOx and CO the emission concentration requirement for NOx was deleted and the requirement for a CO continuous emission monitor was removed.

Revision c (October 19, 1999): Removed CO emission limit and monitoring requirement based on decreased CO emissions resulting from burner change out.

Revision d (June 28, 2002): Removed reference to CO in Condition 7 which was removed in previous revisions, and added monthly reporting of NOx in monthly emission reports.

Revision e (May 10, 2010): Changed NOx emission limit from 0.07 lb/MMBtu and 66 NOx tons per year to 33 ppmvd and 8.36 lb/hour, which is equivalent to an emission factor of 0.04 lb/MMBtu. A CO limit was also added to the OAC. These permit revisions were done to facilitate a federally enforceable NOx reduction accomplished by a project to modify the flue gas recirculation (FGR) system in the #4 Boiler. The FGR modification project provided creditable NOx reductions to meet BP's 2001 Consent Decree obligations. OAC 351e became effective on November 11, 2010, with the startup of the #4 Boiler following completion of the #4 Boiler FGR modification project. OAC 351e superseded OAC 351d on its effective date.

All conditions of OAC 351e have been incorporated into the AOP, with the exception of one-time only conditions that have been completed. Condition 3 required an initial source test for NOx within 90 days of startup from the #4 Boiler after completion of the FGR modification project. The initial source test was completed on December 15, 2010, demonstrating compliance with the established NOx emission limits. No further testing was required because a CEMS was installed as required within 180 days of startup after completion of the FGR modification project. Condition 9 required that an initial startup notification be submitted within 15 days following startup after completion of the FGR modification project. This startup notice was received by the NWCAA on November 19, 2010, indicating that initial startup of the #4 Boiler following completion of the FGR modification project occurred on November 11, 2010.

During initial permitting of the #4 Boiler, the refinery netted out of PSD applicability for NOx through a NOx reduction of 27 tons per year at the Hydrocracker 1st Stage Fractionator Reboiler. This reduction was accomplished by retrofitting the 1st Stage Fractionator Reboiler with low-NOx burners as required by OAC 351a Condition 10. On May 28, 1993, the refinery submitted a letter stating that the NOx reductions associated with the 1st Stage Fractionator Reboiler low-NOx burner project had been validated with pre-project and post project source testing. On May 10, 2010, the NWCAA issued OAC 351e for the #4 Boiler Flue Gas Recirculation (FGR) system modification project. This permit includes language to supersede OAC 351d, and activate OAC 351e upon startup of the #4 Boiler following completion of the FRG modification project. Startup of the #4 Boiler following completion of the FGR modification project occurred on November 11, 2010.

On November 29, 2010, the NWCAA issued OAC 1067 authorizing replacement of the low-NOx burners on the Hydrocracker 1st Stage Fractionator Reboiler with state-of-the-art ULNB. This NOx reduction project was approved as a PSD netting offset project for the BP Clean Fuels Project approved under OAC 1064. OAC 1067 revision "a" was issued July 29, 2011. The effective date of OAC 1067a is the startup date of the 1st Stage Fractionator Reboiler following the ULNB retrofit project. On June 4, 2012, the NWCAA received a letter from BP notifying the agency that the reboiler began operating on May 16, 2012, following installation of the ULNB and activating OAC 1067a. OAC 1067a explicitly supersedes OAC 351e, Condition 11 requiring

the 1st Stage Fractionator Reboiler to demonstration compliance with a 27 ton per year NO_x reduction from the 1994 low-NO_x burner retrofit project because the reboiler now has an ULNB.

Periodic stack testing is required for Boiler #4. Testing is normally required at 90% load. NWCAA may, on a case-by-case basis, approve testing at 90% steam load. However, this approval is case-by-case and subject to review prior to each test.

2. #5 Boiler

In 2002, the refinery proposed constructing a new 363 MMBtu/hour boiler to increase the supply of utility steam to support a new Isomerization Unit and to replace the aging #2 Boiler. The #5 Boiler, also referred to as the #2 Replacement Boiler, along with the new Isomerization Unit were approved by Ecology under PSD-02-04 issued May 16, 2003 for PSD major pollutants NO_x and CO. Similarly, the NWCAA approved the #5 Boiler and Isomerization Unit under OAC 814 issued June 2, 2003, for minor air pollutants PM₁₀, SO₂, VOC and HAP. OAC 814 provided the refinery with a federally enforceable SO₂ offset so that the #5 Boiler and Isomerization Unit project was below the PSD significance threshold of 40 tpy. This offset was approved as an SO₂ reduction required under by OAC 814 limiting the H₂S concentration in the Vacuum Tail Gas generated at the Crude and Vacuum Unit to 500 ppm.

The #5 Boiler was constructed and began operating in 2004. Since that time, the PSD permit was revised to its current version, PSD-02-04 Amendment 1, on April 20, 2005. The NWCAA order was revised to OAC 814a on April 24, 2004, and again to its current version OAC 814b on July 9, 2012. OAC 814b was issued to improve formatting and to clean up the order for better incorporation into the air operating permit.

Periodic stack testing is required for Boiler #5. Testing is normally required at 90% load. NWCAA may, on a case-by-case basis, approve testing at 90% steam load. However, this approval is case-by-case and subject to review prior to each test.

3. #6 and 7 Boilers

To replace the aging #1 & 3 Boilers, each rated at 330 MMBtu HHV per hour, the refinery proposed constructing two new boilers. On November 19, 2007, Ecology issued PSD-07-01 authorizing construction of the #6 & 7 Boilers each rated at 363 MMBtu per hour. The PSD permit limits the emission of PM₁₀, SO₂ and CO, that are each considered major PSD pollutants. Similarly, on November 29, 2007, the NWCAA issued OAC 1001 approving the #6 & 7 Boilers both equipped with low NO_x burners and selective catalytic reduction (SCR) to control NO_x emissions. The OAC was revised three times to its current version, OAC 1001c issued May 20, 2013. The new boilers were constructed and began operating in March of 2009.

OAC 1001c Condition 10 required decommissioning the #1 & 3 Boilers within 12-months of the first startup of either the #6 or the #7 Boiler. #6 Boiler was the first to startup on March 27, 2009, triggering the requirement to decommission the #1 & 3 Boilers by no later than March 27, 2010. On January 14, 2010, the NWCAA received a written notice from the refinery that the #1 Boiler was decommissioned on October 28, 2009, and the #3 Boiler was decommissioned on October 3, 2009. Since it had been fulfilled, the requirement to decommission the #1 and #3 boilers was not incorporated in AOP 015R1M1.

The #6 & 7 Boiler startup notifications were received by the NWCAA on April 8, 2009. The notice stated that #6 Boiler commenced operation on March 27, 2009 and that #7 Boiler commenced operation on March 28, 2009.

One-time only initial source testing for CO, SO₂ and PM₁₀ as required by PSD-07-01 was completed in August 2009, and testing for PM and Ammonia in September 2009. These source tests demonstrated that the #6 & 7 Boilers were in compliance with the applicable limits of the

PSD permit. Ongoing compliance with NO_x and CO limits are demonstrated with CEMs. Ongoing compliance with PM₁₀ and ammonia limits is demonstrated through periodic source testing. In addition, an ammonia monitoring plan is used to prevent excessive ammonia slip. Ongoing compliance with SO₂ limits are demonstrated through periodic analysis of the refinery fuel gas for total sulfur.

Periodic stack testing is required for Boiler #6 and Boiler #7. Testing is normally required at 90% load. NWCAA may, on a case-by-case basis, approve testing at 90% steam load. However, this approval is case-by-case and subject to review prior to each test.

On March 31, 2009, BP Cherry Point Refinery and the NWCAA signed NWCAA Administrative Compliance Order 01. The order was drafted after BP recognized a significant potential for the #6 & 7 Boilers to exceed the SO₂ 13.6 lb/hr, 3-hr rolling limit of PSD-07-01. The order supported load shifting between refinery boilers to mitigate an exceedance. On December 11, 2009, as specified in the order, Administrative Compliance Order 01 was considered null and void upon issuance of PSD -07-01 Amendment 1. The PSD amendment increased the SO₂ limit from 13.6 to 39.3 lb/hour, 3-hour average, thereby reducing the risk of non-compliance with the SO₂ limit.

4. #2 Cooling Tower

In 1990, the refinery proposed construction of a second cooling tower to address a cooling capacity deficit. The NWCAA approved the #2 Cooling Tower with a heat release rate of 500 MMBtu/hour under OAC 289 issued August 23, 1990. The approval order required a hydrocarbon monitor installed and operated in accordance with manufacturer's specifications. The refinery installed a combustion analyzer to monitor the explosive limit of the vapors exiting the cooling tower.

On April 12, 2012, the NWCAA issued revised OAC 289a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.12 Flares

Another part of the Utility process unit is the flare system. The flare system thermally destroys gasses of various flow rates and compositions. It also destroys gasses released during upsets, malfunctions, and routine operations.

There are two flares at the refinery. They are control devices necessary for the safe operation of the refinery and can alternate service. The High Pressure flare is connected to higher pressure, higher volume units such as the Hydrocracker unit. The Low Pressure flare is connected to the lower pressure, lower volume units such as the LPG unit. The flares are designed to handle a wide range of flow rates including emergency releases of refinery gasses in the event that a unit shuts down or controlled releases of gasses when a single piece of equipment is shut down for maintenance. The flares are equipped with recovery compressors to capture the maximum amount of gasses possible which are then recovered and treated to remove H₂S and recycled to the refinery fuel gas system. Steam is injected (steam-assisted) at each flare tip to create turbulence needed to enhance mixing of flared hydrocarbon gasses with ambient air for better combustion. When done properly, visible emissions from flaring are kept below 20%.

Major equipment for this unit are the High Pressure Flare, Low Pressure Flare, recovery compressors, pumps, valves, flanges and drains. Emissions associated with the flares include VOCs, PM, HAPs and SO₂.

Both flares were installed during the original construction of the refinery in 1970. A design analysis was completed on the flares and submitted to the NWCAA in January 1999 as part of the refinery's Initial Notification of Compliance Status Report under 40 CFR 63 Subpart CC. 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 MACT Group 1 process vents and for control of leaks from pump seals, regulated equipment leaks in HAP service.

There are three primary compressors that are used to mitigate hydrocarbon flaring. These are the high and low pressure flare gas recovery compressors and delayed coker wet gas recovery compressor. The high and low pressure flare gas recovery compressors route recovered gasses to amine treatment for H₂S removal and then to the refinery's main fuel gas system. Whereas, the Delayed Coker wet gas recovery compressor processes recovered gasses within the Delayed Coker Unit.

Any time one of these compressors is down for maintenance, the refinery is considered in an alternative operating condition and must be careful with regard to using remaining compressor capacity in order to continue to meet its compliance obligations at the flares.

The compressors can recover gasses to a certain inlet pressure, and if the pressure or volume exceeds the compressor capacity, some of the gas will go to the flares. The reciprocating high and low pressure flare gas recovery compressors require regular maintenance shutdowns, so while one is shutdown the other compressor must be connected to the low pressure flare. If the Coker Blowdown Vapor Recovery Compressor system is down, Coker blowdown gas is sent to the Flare Gas Vapor Recovery System. There are various compressor line-up choices that are used to minimize flaring emissions. Maintenance shutdowns are scheduled to minimize emissions. Due to the sour (i.e., high sulfur content) characteristics of the Coker blowdown gas, a potential exceedance of the 1,000 ppm SO₂ limit of NWCAA 462 may occur at the flare when Coker blowdown vapors are not fully recovered.

3.13 Sulfur Recovery Complex

The Sulfur Recovery Complex is comprised of several units: DEA Unit, Sour Water Stripper, sulfur recovery unit (SRU), two Tail Gas Units (TGUs), and sulfur storage tanks and pits. The sulfur complex is designed to destroy NH₃ and process H₂S as well as other sulfur-containing compounds by converting them into elemental sulfur that can be sold. The SRU is composed of two trains, North and South. Two TGUs serve the two sulfur recovery trains.

Crude oil may contain significant amounts of sulfur compounds. Hydrodesulfurization and hydrocracking convert much of the sulfur into H₂S. Some of the H₂S is dissolved in water and is treated in the sour water stripper. However, much of the H₂S goes to the refinery fuel gas system. H₂S is removed from the refinery fuel gas system by passing the fuel gas through an amine-based DEA unit. DEA units are located at the Coker, Hydrocracker, Naphtha HDS, Diesel HDS, LEU, Sour Water and Flare Gas recovery units. DEA absorbs H₂S from the refinery fuel gas. The absorbed H₂S creates a rich DEA mixture that is regenerated using steam. At the DEA Unit concentrated H₂S is liberated and this high concentration H₂S-laden stream is routed to the Sulfur Recovery Unit where it is converted into elemental sulfur.

As mentioned previously, another source of H₂S at the refinery is sour water. The Sour Water Unit collects water throughout the refinery known to contain H₂S as well as NH₃. H₂S and NH₃ are stripped from the water in the Sour Water Unit. The removed H₂S and NH₃ are routed to the SRU for further treatment.

The SRU converts the recovered and stripped H₂S into elemental sulfur using a catalytic reaction generically referred to as the Claus process. Typically, one third of the H₂S is oxidized to SO₂ with air while the remaining H₂S reacts with SO₂ to form elemental sulfur. NH₃ is destroyed as part of this process (taking the form of N₂). The hot gasses formed in the SRU reaction are fed through waste heat boilers to generate steam. Following heat recovery the cooled gasses are routed through sulfur condensers in which the elemental sulfur is removed and sent to sulfur tanks and/or sulfur pits for storage.

However, the Claus process is not 100% complete. As a result the remaining gas, referred to as tail-gas, is treated in the Tail Gas Units. The Tail Gas Units are designed to recover most of the remaining sulfur compounds before exhausting to the atmosphere. The TGUs are designed to control SO₂ to the NSPS Subpart J standard of 250 ppm, 12-hour rolling average. The #1 TGU accomplishes this using a three step process: hydrogenation, hydrolysis, and H₂S absorption. Untreated tail gas undergoes hydrogenation and hydrolysis in which SO₂ and other sulfur compounds are converted into H₂S. The newly formed H₂S is then absorbed in using a methyl-diethanolamine (MDEA) based counter-current extractor. The rich MDEA is regenerated with steam, and the liberated H₂S is routed to the SRU for conversion into elemental sulfur. The remaining residual unabsorbed H₂S in the tail gas stream is routed to an incinerator where the remaining H₂S is oxidized to SO₂ and exhausted to the atmosphere.

The #2 TGU uses a proprietary CanSolve® process to remove sulfur from the tail gas stream. Prior to absorption H₂S and other reduced sulfur compounds are converted to SO₂ in the thermal oxidizer. The oxidized gas is cooled and the SO₂ absorbed in a lean diamine solution. The SO₂ rich diamine is regenerated using steam, and the concentrated SO₂ is routed to the SRU for conversion to elemental sulfur. Residual SO₂ that is not absorbed is exhausted to the #2 TGU stack.

Emissions from the sulfur complex are primarily SO₂ from the incinerator and #2 TGU stacks. Each stack is equipped with a CEM to continuously monitoring SO₂ emissions. NO_x, CO, PM₁₀, VOC and HAP emissions are generated as products of combustion in the SRU, incinerator and thermal oxidizer.

When the #2 Tail Gas Unit (TGU) is operated during periods that the #1 TGU down for maintenance, the refinery may need to reduce the sulfur production rate at the Sulfur Recovery Complex in order to meet its ongoing compliance requirements. In this operating mode only one Claus Unit is operated due to TGU capacity limitations.

Emissions from the elemental sulfur pits and tanks located at the Sulfur Recovery Complex are controlled with the Sulfur Pit Vapor Recovery (SPVR) system that uses a counter current wet scrubber using caustic solution as the absorption media. When the SPVR system is down for maintenance which is often due to the formation of sulfite and sulfate salts in the system, gasses from the sulfur pits and tanks are routed directly to the #1 TGU incinerator. The incinerator stack is equipped with an SO₂ CEM and therefore, ongoing compliance is still continuously monitored. However, this situation is considered an alternative operating condition because it is not the normal mode of operation.

Construction History and Regulatory Applicability

The sulfur complex comprised of the north and south sulfur recovery trains (CLAUS trains) was built along with the original refinery in 1970. Following construction it was determined that the sulfur recovery complex could not meet the NWCAA 462 regulation limiting stack SO₂ emission to 1,000 ppm at 7% oxygen. On March 13, 1974, the NWCAA issued a variance that required the refinery to comply by July 1, 1977. In 1975, the #1 Tail Gas Unit (#1 TGU) was added to the Sulfur Recovery Complex bringing the refinery into compliance with NWCAA 462. NWCAA issued an unnumbered OAC dated June 30, 1977 approving the #1 TGU. The approval letter included a condition that limited elemental sulfur production to 127 long tons per day and required a source test to demonstrate compliance with the 1,000 ppm @ 7% oxygen SO₂ limit. In a July 9, 1990 letter, the NWCAA granted the refinery permission to increase their elemental production sulfur rate with the condition that a CEM for SO₂ be installed on the incinerator stack. The CEM was installed and certified on February 27, 1995, thereby lifting the requirement to operate within a long ton per day elemental sulfur production limit at the sulfur recovery complex.

On June 14, 1984, the NWCAA approved construction of a second elemental sulfur storage tank at the sulfur recovery complex under OAC 290. The refinery did not plan to increase sulfur

production rates as a result of adding the tank and identified fugitive H₂S as the only emission associated with the new tank. OAC 290 does not include any specific conditions or requirements; therefore, this OAC is not referenced in the air operating permit.

The 2001 Consent Decree required applicability of 40 CFR 60 Subpart J requirements at the Sulfur Recover Complex. Subpart J requires that emissions of SO₂ do not exceed 250 ppmvd @ 0% oxygen, 12-hour rolling average limit on the sulfur recover complex incinerator stack. On May 15, 2002, the NWCAA formalized this requirement under Regulatory Order 28. The 2001 Consent Decree (paragraph 21) also required the refinery to construct a second tail gas unit to provide process redundancy and eliminate acid gas flaring during #1 TGU maintenance activities. Construction of the second tail gas unit was required by the end of 2006 to assure consistent ongoing compliance with 40 CFR 60 Subpart J. Following submittal of an NOC application, on February 22, 2005, the NWCAA issued OAC 890 authorizing construction of the #2 TGU. Startup of the #2 TGU occurred on June 30, 2006.

Because the project increased the sulfur handling capacity of the sulfur recovery complex by about 12%, the resultant potential increase in SO₂ emissions was offset with the Coker Blowdown Vapor Recovery Project to prevent SO₂ emission from triggering PSD thresholds. The Coker Blowdown Vapor Recovery Project reduced SO₂ emissions by capturing sour coker drum blowdown vapors using the previously underutilized capacity at the Delayed Coker Wet Gas Compressor. As required under OAC 890, the Coker Blowdown Vapor Recovery Project completed prior to startup of the #2 TGU. Because the addition of the #2 TGU impacted overall operation at the sulfur recovery complex, OAC 890 was written to supersede previously applicable orders issued by the NWCAA.

On October 26, 2005 revision OAC 890a was issued providing an alternative monitoring plan for monitoring emissions from the sulfur pit and sulfur tank during periods when the caustic scrubber and/or #1 TGU incinerator is off-line for maintenance. On February 25, 2009, revision OAC 890b was issued adding clarification to applicability of the SO₂ limit during startup, shutdown and malfunction events. The revision also removed NO_x, CO, H₂SO₄ and H₂S emissions limits for the #2 TGU stack because the emissions limits were based on a one-time only demonstration of compliance through source testing. This testing was completed in August 2006 and October 2008 showing compliance with the NO_x, CO, H₂SO₄ and H₂S limits of OAC 890a. OAC 890b included a new requirement for annual source testing of the #2 TGU for SO₂ because of the complexities inherent using calculating stack flow rates and converting ppm values from the CEM to lb/hour and tpy mass emission rates. Lastly, OAC 890b included a new provision to allow bypassing of the caustic scrubber controlling sulfur pit and elemental sulfur tank emissions for up to 240 hours per year to accommodate expected maintenance activities on the scrubber. 40 CFR 60 Subpart Ja includes this 240 hour bypass clause.

The 240 hour bypass provision from controlling emissions from the sulfur pit and elemental sulfur tanks is not included in 40 C FR 60 Subpart J which is the applicable NSPS standard at the Sulfur Recovery Complex. Because bypassing events do not alleviate the refinery's requirement to comply with the 40 CFR 60 Subpart J, the 250 ppm SO₂ emission limit is applicable at all times. The OAC includes an alternative monitoring plan using colorimetric detector tube sampling for SO₂ and H₂S that is used to demonstrate compliance with Subpart J during periods when the scrubber is being bypassed.

On July 21, 2011, the NWCAA issued revised OAC 890c authorizing an alternative operating configuration at the Sulfur Recovery Complex that allows facility to produce up to 270 long tons per day (LTPD) of elemental sulfur. Prior to construction of the #2 TGU, each of the two Claus trains were nominally rated at 100 LTPD of elemental sulfur production with the #1 TGU serving to control post-Claus SO₂ emissions. When the #2 TGU was constructed in 2005, the project included tie-ins to existing equipment allowing concentrated SO₂ generated at the #2 TGU to be routed to the front end of each Claus train. This had the effect of improving sulfur recovery in the Claus units. The NOC application for OAC 890 estimated that the improved Claus efficiency

would result in an overall elemental sulfur production capacity increase at the facility of 12.5%, or from 200 to 225 LTPD.

The #2 TGU was constructed as a first-time application of a proprietary CanSolv® diamine SO₂ absorption system with regard to serving as a refinery sulfur recovery tail gas control system. After a five year shake out period at the refinery including various system adjustments to the #2 TGU, it became apparent that the Sulfur Recovery Complex could operate in a configuration optimized for sulfur removal efficiency with operational stability producing to 270 LTPD of elemental sulfur and remain in compliance with all applicable emission limits. This could be done with no physical changes because the Sulfur Recovery Complex was capable of accommodating the configuration following completion of the #2 TGU project in 2005.

On May 29, 2009, the NWCAA issued OAC 1043 approving the Sour Water Handling Project at the Sour Water Unit. The project was completed and placed into service on April 24, 2010. The project included the addition of a second flash drum and replacement of components in the non-phenolic stripper tower to provide a designed increase in the sour water processing capacity from 760 to 1,005 barrels per hour. The project added one new MACT Group 1 vent that is routed to the flare gas recovery system. The project also triggered applicability of 40 CFR 60 Subpart GGGa, which references Subpart VVa as the federal enhanced LDAR standard.

On May 29, 2009, the NWCAA issued OAC 1043 approving the Sour Water Unit upgrade project. The project included the addition of a second flash drum and replacement of components in the non-phenolic stripper tower to provide a designed increase in the sour water processing capacity from 760 to 1,005 barrels per hour. The project added one new MACT Group 1 vent that is routed to the flare gas recovery system. The project also triggered applicability of 40 CFR 60 Subpart GGGa, which references Subpart VVa as the federal enhanced LDAR standard.

The project was completed and on September 23, 2010, a notice of startup was received by the NWCAA as required by Condition 2 of OAC 1043. Because this one-time only requirement has been completed, OAC 1043, Condition 2 is not cited in the air operating permit.

3.14 Shipping, Pumping and Receiving

Shipping, pumping, and receiving involve numerous processes and areas. For the purposes of the AOP, NWCAA divided this area into four units: Chemical Treater, Truck Rack, Marine Terminal, and LPG/LEU/Butane/Pentane Loading. Tankage associated with these units is discussed in Section 1.14. The following is a discussion of each unit.

1. Chemical Treater

The Chemical Treater consists of two separate processes, a stove oil treater and a diesel treater. The stove oil treater is designed to remove water and other impurities from the stove oil. The diesel treater is designed to remove water from diesel fuel.

2. Truck Loading Rack

The Truck Loading Rack is used to load gasoline, jet fuel and diesel products into truck cargo transport tanks. The facility contains loading lanes, each equipped with two bottom loading stops; one for the front tank and one for the rear tank. Each loading arm contains dedicated loading arms for gasoline, diesel and jet fuel. LPG can also be loaded at the truck rack. Automatic interlock devices are in place to prevent loading unless appropriate thermal oxidation temperatures in the vapor combustor are met and to assure that the tanks loaded have a valid annual leak tightness test certification on record. Under OAC 527d, the Truck Loading Rack is limited to 26,000 barrels of gasoline per day, and the total loadout of diesel and jet fuel is limited to 76,000 barrels per day.

For regulatory purposes the vapor combustor is considered a thermal oxidation unit, because the oxidation process is enclosed and combustion temperatures monitored. The vapor

combustion device uses natural gas as a supplemental fuel to assure that the temperature in the oxidizing zone is at or above 1,200°F at all times when displaced vapors are routed to it during loading. This baseline temperature was determined during initial performance testing required pursuant to applicable federal regulations. The NWCAA was notified of the result of the initial testing in a December 27, 1995 letter from the refinery. Operation at an average temperature of 1200°F ensures that the emission standard of 10 milligrams VOC per liter loaded will be met.

VOCs and HAPs are also emitted from loading losses and equipment components (pumps, flanges, valves, pressure relief devices) and from emissions from storage tank emissions.

Construction of the Truck Loading Rack was proposed on October 6, 1994. The project included the construction of three new finished product storage tanks (Tanks #72, 73 & 74). The NWCAA issued OAC 527 on December 24, 1995, approving construction of the Truck Loading Rack and tanks. On August 27, 1996 the refinery proposed to modify the Truck Loading Rack by adding a new bay for the delivery of jet and diesel fuel. The NWCAA issued OAC 527R2 on October 24, 1996, (OAC 527R1 was issued on September 27, 1996 with an incorrect capacity for one of the diesel tanks) approving the project. On November 6, 2001, the refinery proposed to increase the throughput of the Truck Loading Rack without any physical modifications. On December 13, 2001, the NWCAA approved the increase under OAC 527c.

On July 9, 2012, the NWCAA issued revised OAC 527d which explicitly superseded all previous versions of this order. The revision eliminated confusing overlap between requirements in federal, state and NWCAA regulations and those contained in the order. The revision also improved formatting and cleaned up the order for better incorporation into the air operating permit.

There are a number of overlapping regulations that apply to the Truck Loading Rack. These include; NWCAA 580.4, WAC 173-491-040 (2), 40 CFR 60 Subpart XX, and 40 CFR 63 Subpart CC (Refinery MACT). Equipment components in VOC/HAP service are under a leak detection and repair (LDAR) program pursuant to NWCAA 580 (RACT), 40 CFR 60 Subpart GG (NSPS) and 40 CFR 63 Subpart CC (MACT). In addition fugitive VOC emissions from the oily wastewater system at the Truck Loading Rack are regulated under 40 CFR 60 Subpart QQQ. 40 CFR 63 Subpart CC (Refinery MACT) applies a modified version of 40 CFR 63 Subpart R at the Truck Loading Rack. As such, only those portions of Subpart R listed in 40 CFR 63.650 of Subpart CC are cited in the air operating permit.

3. Marine Terminal

The marine terminal is used to unload crude oil from ships and barges, and to load products onto ships and barges such as gasoline, gasoline blending components, diesel, jet fuel, and intermediates such as hydrocrackate, and reformate. The south berthing dock has crude oil unloading capability. The north berthing dock is equipped to load liquids onto ships and barges, however, it does not have equipment that would enable unloading operations.



The docks consist of a loading platform, trestle end platform, connecting trestle platform, trestle head platform, wye connecting bridges, and wye pipe bridge. Hydrocarbon product loading arms and a vapor collection system are located on the loading platform on the north berthing dock. A vapor collection knockout pot, vapor blower, and liquid seal skid, and a vapor combustor are located at the trestle head platform. The vapor combustor is considered a thermal oxidizer because vapors collected during loading are combusted within an enclosed device.

Vapors are collected through an arm connected to the vessel being loaded. The vapors first pass through a detonation arrestor, then natural gas is added to enrich the gas stream above the upper explosive limit (UEL). Enriched vapors are transported through a 12-inch pipe to the trestle head platform where the blower skid and vapor combustor are located. The vapors pass through a knockout pot to remove any entrained liquid, then the blower, the liquid seal, and another detonation arrestor. The liquid seal and detonation arrestors ensure that flames cannot flash back through the vapor collection pipe. Finally, the vapors are injected into the vapor combustor (thermal oxidizer) and destroyed through combustion with a designed minimum destruction removal efficiency of 98 percent.

Construction History and Regulatory Applicability

The trestle way and south berthing dock were constructed as part of the original refinery construction in 1971. On June 7, 1993, the NWCAA issued OAC 437 approving a project to modify the dock piping system. On January 26, 2000, the NWCAA issued OAC 716 approving construction of the north berthing dock. This second berthing area was needed to alleviate scheduling problems, reduce demurrage costs, and increase product shipping flexibility. The north berthing dock was designed specifically to handle product loading onto ships and barges, and does not have equipment to facilitate unloading of crude oil.

On May 3, 2001, the NWCAA issued OAC 716a approving a project to connect the vapor collection and vapor combustor control system to the south dock. As approved, all vapors that are displaced during ship and barge loading of light liquids (i.e., vapor pressure ≥ 1.5 psia) at both the north and south docks are collected and routed to the vapor combustor for control.

On July 9, 2012, the NWCAA issued OAC 716b. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit. OAC 716b explicitly superseded OAC 437 and therefore, OAC 437 is no longer valid and not cited in the air operating permit.

After construction of the north dock, the Marine Terminal became an affected facility under 40 CFR 63 Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations. In

accordance with §63.650(a)(1), the facility was considered a new MACT source under Subpart Y with emissions from the Marine Terminal below the 10 tons of any single HAP, or 25 tons of a combination of HAP. In accordance with §63.650(b)(1), the Marine Terminal is also considered a RACT source under Subpart Y, because gasoline loading exceeded the 10 million barrel annual average applicability threshold of the rule. Subpart Y requires that emissions of VOC be controlled by at least 98% by weight during loading of all light liquids, and to no more than 1,000 VOC ppmv during the loading of gasoline. Compliance is demonstrated through a one-time initial source test using EPA Method 25 and the establishment of a baseline temperature at which the vapor combustor is to be operated. In April 2002, the refinery conducted initial source testing of the vapor control system as required under Subpart Y. During the test, the exhaust temperature of the vapor combustor's thermal oxidizer was monitored and a baseline temperature established of 1350°F for demonstrating ongoing compliance with each block hour cycle. In accordance with Subpart Y, the average 3-hour block average temperature must remain at or above 1350°F for the vapor combustor to demonstrate ongoing compliance with the rule.

40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries includes an overlap provision for marine terminals.

40 CFR 63.651 - Marine tank vessel loading operation provisions

(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§63.560 through 63.568.

The Subpart CC overlap provision does not change any of the emission limits, monitoring or recordkeeping requirements of Subpart Y.

40 CFR 60 Subpart J - New Source Performance Standards for Petroleum Refineries is not an applicable regulation at the marine terminal for two reasons. First, the definition of fuel gas under Subpart J specifically exempts gas generated from marine tank vessel loading operations. Secondly, the thermal oxidizer at the marine terminal uses only natural gas (a supplemental fuel) as a pilot and to maintain combustion temperatures. Because the refinery-generated gas is not combusted at the marine terminal either as recovered vapors during loading, or as supplemental fuel in the thermal oxidizer, 40 CFR 60 Subpart J is not an applicable regulation at this facility.

4. LPG/LEU/Butane/Pentane Loading

Gaseous products, such 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. Propane, butane, and pentane are typically loaded into rail cars. Propane can also be loaded into trucks at the truck rack. Equipment that emits pollutants such as VOCs and HAPs include pumps, valves, flanges, and seals. As a result, these pieces of equipment are subject to the refinery's LDAR program as well as NWCAA 580.

5. Crude Rail Car Unloading Facility The applicable NSPS, NESHAP, and MACT regulations are:

A new crude rail car unloading facility was approved under OAC 1142 on January 22, 2013. The facility includes a 1.9 mile rail loop and an unloading area capable of accommodating the concurrent unloading of up to 52 railcars. OAC 1142 did not approve an increase in crude processing capacity. The approval nearly provided BP with the ability to ship more crude feedstock via rail as opposed to shipping via ship or pipeline. The facility was construction in 2013.

Regulatory Applicability

6.

- 40 CFR 60 Subpart QQQ
- 40 CFR 61 Subpart FF
- 40 CFR 63 Subpart CC

On December 12, 2013 NWCAA received BP's notification of compliance with the applicable provisions for NSPS Subpart QQQ, 40 CFR 63 Subpart CC, and 40 CFR 61 Subpart FF.

40 CFR 60 Subpart GGGa does not currently apply to the Rail Logistics Project because the railcar unloading facility is not considered a "process unit" as defined in Subpart GGGa. As presented below, the expanded definition of "process unit" has been stayed and at this time the narrower version of the definition is being applied that limits applicability to traditional refinery process units, but not shipping, receiving or storage operations.

*40 CFR 60.590a(e): 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:*

While 40 CFR 60 Subpart GGGa doesn't technically apply, the requirements of the subpart are being relied on as BACT in OAC 1142 Condition 7 (AOP term 5.15.44). BP's December 12, 2013 notification of compliance included a statement that the facility is complying with the requirements of 40 CFR 60 Subpart GGGa.

3.15 Landfarm

On May 8 1992, the refinery proposed construction of a new non-hazardous waste landfarm to replace the existing non-hazardous waste landfarms that began operating in 1971. The new landfarm is used to treat and dispose of non-hazardous waste, including oily wastes and waste biomass from the oil wastewater treatment plant. Dangerous wastes, as defined by WAC 173-303 are not allowed. The landfarm conforms to the Washington State standards for solid waste handling under WAC 173-304. The landfarm is located on top of existing clean construction fill. Potential emissions include air toxics such as benzene and ammonia.

On June 30, 1992 the NWCAA issued OAC 382 approving the new non-hazardous waste landfarm. On May 15, 2012, the NWCAA issued revised OAC 382a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

3.16 Oily Wastewater Collection, Storage and Treatment

The Wastewater Treatment (WWT) plant treats oil-contaminated wastewater from the refinery 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. Oily water and storm water are drained to the wastewater from the process units through separate sewers. Sanitary sewage is pumped to Birch Bay for treatment. Oil that is recovered at the Effluent Plant is sent back to the Refinery for processing. Treated wastewater is discharged into the Georgia Strait.

The WWT is designed to handle abrupt changes in flow while still separating water, oil, and solids. It employs flow equalization, settling, floatation, skimming, clarification and enhanced biological treatment. The API Separators collect wastewaters from a variety of areas including process units, laboratory samples, tank farm, and certain remediation wastes. Ship ballast is routed through Tank 320 for flow equalization and then routed to the API Separators. Additionally, vacuum trucks throughout the refinery can discharge through dewatering operations wastewater to the API Separators.

At the API Separators, oils, solids, and water are separated through setting and skimming. Recovered oils are stored in Tanks 321, 322 and 26 prior to being sent back into the refinery. Settled solids are routed to the sludge holding area then dewatered. The water portion from the API Separators is stored in Tanks 323 and/or 320 for flow equalization prior to being treated in the enhanced biodegradation unit then discharged to the Georgia Strait. Biosolids from the biodegradation unit are produced and dewatered as necessary.

Major equipment at the WWT include: Sewers, forebay, API Separators; Tanks 320, 321, 322, 323; carbon canisters; enhanced biodegradation unit; and biosolids handling. Waste streams in each process unit are managed in individual drain systems that contain water seals. Tank water draws and remediation wastes are managed in controlled individual drain system. All individual drain systems are connected to common API Separators (4) where vapors are controlled with carbon canisters. There are 12 adsorbers, six of which are on-line and six which serve as spares when breakthrough is detected on the primary units. All tanks that managed benzene waste streams are controlled with floating roofs. Waste streams that are managed in vacuum trucks are discharged into controlled tanks. All benzene waste streams are controlled except for one remediation waste stream and a small quantity that is transferred off-site or to the land farm. The remediation waste stream flows into a controlled system. Pollutants associated with the WWT are primarily VOCs and HAPs including benzene. Other components that are sources of emissions include valves, flanges, seals, and drains.

Construction History and Regulatory Applicability

The majority of the WWT plant was constructed with the original refinery in 1970. In 1991, the refinery was required to become into compliance with 40 CFR 61 Subpart FF National Emission Standards for Benzene Waste Operations. The refinery's TAB of 32 tons/yr was above the 10 Mg/yr threshold listed in 40 CFR 61 Subpart FF.

The refinery complies with 40 CFR 61 Subpart FF through the requirements of 40 CFR 61.342(c)(3)(ii). This standard requires that the refinery can exempt waste streams by demonstrating that initially and at least once a year thereafter that the either:

- The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gpm) or an annual wastewater quantity of less than 11 tons/year; or
- The total annual benzene quantity in all waste streams chosen for exemption does not exceed 2.0 Mg/yr (2.2 tons/year) as determined by 40 CFR 61.355(j); and that stream selected for exemption, including process turnaround waste, is determined for the year in which the waste is generated.

In addition to 40 CFR 61 Subpart FF, there are wastewater drains that were built after the NSPS applicability date of May 4, 1987, thereby triggering 40 CFR 60 Subpart QQQ requirements for VOC control. These include process drains at the Crude/Vacuum Unit (OAC 640). Downstream of these NSPS drains, the wastewater enters a sewer system controlled under 40 CFR 61 Subpart FF. Through an overlap provision, Refinery MACT 63.640(o) allows for consolidation of wastewater programs by stating that "a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart." In Refinery MACT, a Group 1 wastewater stream is equivalent to the definition of a benzene waste stream found in 40 CFR 61 Subpart FF. Therefore Subpart FF becomes the single applicable standard. The majority of changes to the WWT have been driven by compliance with 40 CFR 61 Subpart FF. The following is a discussion of those changes. For information regarding individual drain systems please refer to 40 CFR 60 Subpart QQQ under NSPS requirements in Section 2.3 of this SOB.

1. API Separator Covers.

On September 15, 1989, the refinery proposed to install floating covers on the forebays and main bays of the API oil/water separator in order to reduce VOC and benzene emissions at the wastewater treatment plant. The refinery estimated that VOC emission would be reduced by 2,543 tons per year at the forebays and 636 tons per year at the main bays as a result of the project. On December 13, 1989, the NWCAA adopted a requirement to cover API oil/water separator forebays under Subsection 580.23 of the NWCAA Regulation. On March 7, 1990, EPA promulgated 40 CFR 61 Subpart FF—National Emission Standard for Benzene Waste Operations requiring covers or alternate controls on both the API oil/water separator forebays and main bays. On April 17, 1990, the NWCAA issued OAC 272 approving the project cover the forebays and main bays consistent with NWCAA and federal requirements. OAC 272 does not include any specific requirements; therefore, this approval order is not referenced in the air operating permit.

2. Wastewater System Benzene NESHAP Modifications

On October 23, 1991 the refinery submitted their application to make modifications to the oily wastewater system in order comply with 40 CFR 61 Subpart FF. The refinery had selected the option to comply with this regulation by sealing the collection and treatment system from each drain system up to the activated sludge treatment unit. The activated sludge treatment unit met the definition of enhanced biological degradation and was therefore exempt from the regulation. Modifications to the oily wastewater system were approved by the NWCAA under OAC 348 issued January 8, 1992. On May 3, 2012, the NWCAA issued revised OAC 348a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

Changes to the oily wastewater system included:

All process water systems: Seal manhole cover; install seals on tank drains with rubber boots or seal enclosures with hatches; install sealed pop-up vents on junction boxes.

API Separators: Install fixed covers with sealed openings; install carbon filters to collect vapors.

API Pump Sump: Install a combination of fixed and floating covers; install and operate carbon filters to collect vapors.

Secondary API Separators: Install fixed covers with sealed openings; install carbon filters to collect vapors.

Skim Oil Pump: Install floating covers.

Recovered Oil Tanks: Construct internal floating roof Tanks #320, 321 & 322.

Oily Water Surge Tank: Install an internal floating roof.

Ballast Water Tank: Install an internal floating roof – Tank #323

Trickle Filter: remove the trickle filter form service.

Tanks #320, 321, 322, and 323 are equipped with a fixed roof and internal floating roof in accordance with the requirements of 40 CFR 61.351. Individual drains were originally constructed with water seal controls (p-traps). Tank water draws on affected tanks in the storage and handling area are fitted with an air tight boot connecting the drain hub and tank nozzle. All tank drains are equipped with P-traps. All process sewer clean out manhole and junction box covers are plugged and sealed.

The oil water separators have been fitted with a combination of fixed and floating roof covers. Fixed covers are installed on the forebays and main bays, and floating roofs are installed on the effluent sumps. All fixed covers on the are vented to carbon absorber control systems through a

closed vent system. The system includes a nitrogen purge to mitigate the risk of combustion under the roofs.

The wastewater from the API separators enters the aeration basins of an activated sludge process. The aeration basin is an exempt unit according to 40 CFR 61.348(b). The activated sludge system meets the definition of an enhanced biodegradation unit.

All required controls are presently in place and operating. In accordance with 40 CFR 61 Subpart FF, seals on the API covers are visually inspected on a quarterly basis and instrument monitored annually for leaks greater than 500 ppm. Activated carbon beds are monitored for breakthrough (500 ppm) at a frequency that is based on 20% of the carbon bed's estimated life expectancy. Monitoring is encouraged to be done on a more frequent basis, especially when abnormal conditions occur at the refinery that would warrant additional attention potential breakthrough.

3.17 Storage Tanks and Vessels

There are a variety of storage tanks (also referred to as storage vessels) located at the refinery. Tanks configured to store light liquids such as gasoline and crude oil are equipped with internal floating roofs. Tanks configured to store heavy products such as distillates and residual intermediates are equipped with fixed roofs. Most of the tanks are located at the Tank Farm where they store crude oil, feed for process units, intermediate products, blending components, and finished products. Section 1 of the permit includes a table describing each store vessel, its year of construction or modification and comments regarding regulatory applicability.

The level of VOC and HAP control employed is dependent on the size of the tank and characteristics of products being stored. These characteristics include vapor pressure, HAP content and odor potential. Generally, products having a vapor pressure greater than 1.5 psia (0.75 psia under NSPS regulations) at actual storage temperatures are required to control emissions through the use of an internal floating roof with appropriate seals between the tank wall and roof. In addition, these tanks are required to meet specific inspection and repair requirements. Pressurized vessels, although not specifically controlled through regulation, are considered closed systems that do not have the potential for on-going emissions to the atmosphere.

The table below presents the regulatory triggers applicable when storing volatile organic liquids (VOL). Tanks storing VOL that has a vapor pressure less than the regulatory thresholds are required to keep records of type of products stored and their vapor pressures, periods of storage and information about the design specifications for each tank.

Table 3-4 Regulatory Triggers for Storage Tanks and Vessels

Regulatory Trigger	kPa	Psia
NSPS control for tanks $\geq 151 \text{ m}^3$	5.2	0.75
R-MACT and NWCAA control for tanks $\geq 151 \text{ m}^3$	10.4	1.50
NSPS and R-MACT control for tanks $\geq 75 \text{ m}^3$	27.6	4.00
Maximum True VP of stored VOL for EFR or IFR tanks	76.6	11.1
	cubic meters	Gallons
NSPS control for MTVP $\geq 5.2 \text{ kPa}$	75	20,000
NWCAA control for MTVP $\geq 10.4 \text{ kPa}$	151	39,900
R-MACT control for MTVP $\geq 10.4 \text{ kPa}$	177	46,800

Note - Federal regulations use IS units, whereas the NWCAA regulation uses English units.

Because high vapor pressure VOL must be stored in “controlled” tanks, the underlying requirements define how these tanks are configured and monitored. VOL tanks constructed after July 23, 1984 are required meet the requirements of 40 CFR 60 Subpart Kb and are exempt from the requirements of 40 CFR 63 Subpart CC for Group 1 tanks as allowed under the overlap provisions of 63.640(n). Tanks constructed before that date and holding VOL containing HAP as a Group 1 tank is required to meet the requirements of 40 CFR 63 Subpart CC, which refers to the control standards of 40 CFR 63 Subpart G. 40 CFR 63 Subpart CC defines applicability and reporting requirements, whereas Subpart G defines the equipment and monitoring requirements for each tank.

Although the 40 CFR 63 Subpart CC is applicable to vessels storing HAP (Group 1), for all practical purposes, all VOL having vapor pressures over 1.5 psia are likely to contain HAPs greater than the 4% by weight Subpart CC trigger and therefore need controls. Hence, whether the underlying regulation is HAP or VOC driven becomes relatively moot. One overlap provision that helps simplify the compliance program for storage tanks can be found under 40 CFR 63.640(n)(8)(v). This allows NSPS Subpart Kb applicable tanks to share the same reporting requirements for those tanks regulated under Refinery MACT. In essence, it aligns the requirements for report submittal to the semiannually Refinery MACT periodic reports (40 CFR 63.654(g)).

Historically, a number of regulations have driven emission control strategies for product storage at the refinery. In 1989, the NWCAA adopted Section 580 requiring the installation of secondary seals on all EFR tanks storing VOL with MTVP equal to or greater 1.5 psia. The deadline for completing all secondary seal retrofits under NWCAA 580 was December 31, 1999. The refinery met the compliance deadline, having completed all secondary seal work by the end of 1999. On August 18, 1998, Refinery MACT became applicable. Similar to NWCAA 580, the Refinery MACT required secondary seals on EFR tanks however, it allowed for a phase-in period that extends into 2008. As a result, the AOP has been written ignoring the Refinery MACT’s phase- in schedule and instead assumes current applicability of the standard. Another issue considered during the writing of the AOP was the fact that NWCAA 580.32 allows 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.

Because of the regulatory uncertainty associated with 580.322 and 580.323, the AOP is written on the basis that the refinery is using NSPS Subpart Kb as the control method. Therefore, citations to NWCAA 580 include references to the equipment specifications and maintenance sections of 40 CFR 60 Subpart Kb. However, this reference is intended to clarify that the substantive requirements of Subpart Kb apply and does not imply that Kb was necessary triggered. This becomes important when the 40 CFR 63 Subpart CC overlap provisions are analyzed.

Under the current version of NWCAA Section 580 (580.26 and 580.37) there are exemptions allowing the source to only follow a federal rule (NSPS or NESHAP) for controlling emissions

from tanks. However, these exemptions are not found in the current State Implementation Plan (SIP) and therefore cannot be used by the source because they are not federally enforceable. Because of this discrepancy, only the SIP-adopted version of NWCAA 580 citations are found in the AOP.

In addition to the underlying NWCAA and federal regulations, there are some tanks at the refinery that were constructed under a NWCAA OAC. In some cases these OACs do not add any additional requirements not already present in the underlying regulation. However, the OACs are cited as specifically applicable requirements because their conditions are unique and federally enforceable. The following is a discussion of the OACs.

1. Crude Oil Tanks #47 and 48

On August 16, 1973 the refinery proposed construction of two internal floating roof crude oil storage tanks, each with a capacity of 268,000 barrels. On September 17, 1973, the NWCAA issued OAC 116 approving the tanks. On June 21, 1974, the NWCAA issued a letter identifying the tanks as #1947 and #1948 and that the agency had conducted an inspection of the newly constructed tanks. The tanks are currently referred to as Tanks #47 and 48. OAC 116 is considered narrative with no enforceable conditions; therefore, this OAC is not referenced in the air operating permit.

On August 16, 1973, the refinery proposed the construction of three internal floating roof crude oil storage tanks, each with a capacity of 312,000 barrels. On October 12, 1973, the NWCAA issued OAC 120 approving construction the three tanks. It is not clear in the NWCAA record if these tanks were actually constructed.

2. Crude Oil Tank #50

On March 17, 1989, the refinery proposed construction of a 500,000 barrel internal floating roof crude oil storage tank (Tank #50). On May 15, 1989, the NWCAA issued OAC 253 approving the project. On August 8, 2002, the NWCAA issued revised OAC 253a by clarifying that the tank is subject to 40 CFR 60 Subpart Kb. Because OAC 253a is considered narrative with no enforceable conditions, it is not referenced in the air operating permit.

3. Intermediate Storage Tank #71

On March 12, 1992, the refinery proposed construction of a 31,500 barrel internal floating roof storage tank (Tank #71). The tank was designed to be used as an intermediate storage tank for material which is drained from product shipping lines used to load ships and barges at the docks as well as a correction tank to assist in product blending. On May 1, 1992, the NWCAA issued OAC 371 approving the project. On August 8, 2002, the NWCAA revised OAC 371a clarifying that the tank is subject to 40 CFR 60 Subpart Kb and is in organic hazardous air pollutant service subject to 40 CFR 63 Subpart CC. Because OAC 371a is considered narrative with no enforceable conditions, it is not cited in the air operating permit.

4. Finished Product Tank #24

On August 26, 1993, the refinery proposed construction of a 200,000 barrel petroleum internal floating roof storage tank (Tank #24). The tank was designed to be used to store finished diesel product as well as potentially storing other higher vapor pressure liquids such as gasoline. The refinery estimated the maximum true vapor pressure for the tank to be 8.3 psia (gasoline). On November 23, 1993, the NWCAA issued OAC 453 approving the project with a condition that limited the vapor pressure of the stored liquid to 8.3 psia.

On November 18, 1993, the refinery proposed to install a geodesic dome on the internal floating roof rather than the originally proposed internal floating roof design. On November 23, 1993,

the NWCAA issued OAC 453a with a revised condition allowing the vapor pressure of the stored liquid to go as high as 11.1 psia.

On August 8, 2002, the NWCAA issued revised OAC 453b to eliminate overlapping requirements and the revision removed all of the conditions of approval. Because OAC 453b is considered narrative with no enforceable requirements, it is not referenced in the air operating permit.

5. Truck Loading Rack Finished Product Tanks #72, 73 and 74

On October 6, 1994, the refinery proposed the construction of a new Truck Loading Rack for loading gasoline, diesel and jet fuel into truck cargo tanks for transport off-site. The project included the construction of three new internal floating roof storage tanks: two 10,000 barrel tanks, and one 20,000 barrel tank, each tank equipped with a liquid mounted primary seal meeting the requirements of 40 CFR 60 Subpart Kb.

On December 24, 1995, the NWCAA issued OAC 527 approving the project. There have been numerous revisions to this order, the last being OAC 527d issued July 9, 2012, which is cited in the air operating permit. OAC 527d limits the type of products that can be stored in Tanks #72, 73 and 74 and has associated recordkeeping requirements to demonstrate compliance. These requirements are included in the AOP.

Secondary seals were added to all three tanks after they were constructed.

6. Light Reformate Splitter Tower Tanks #1-10, and 14)

As previously discussed, on August 1995 the refinery notified the NWCAA that they proposed to build a new Light Reformate Splitter Tower (LRF Tower) at the #1 Reformer Unit. The project was approved under OAC 526 issued January 3, 1996. On February 14, 1996, the refinery requested a change to the project to allow the use of existing tanks to storage benzene-concentrated LRF Tower bottoms. All of the tanks are configured with internal floating roofs to control emissions. The use of these tanks for handling benzene concentrate was determined to result in an increase in emissions from the project, and this increase was incorporated into the project's WAC 173-460 Tier II Analysis completed by Ecology. On February 26, 1996, the NWCAA issued revised OAC 562a approving the project including the use of existing storage tanks to store benzene concentrate from the LRF Tower.

On May 6, 1996, the refinery began operating the LRF Tower. Once operating, they determined through computer optimization that the LRF Tower bottoms could be further concentrated to 70% by weight benzene from the original 40% by weight estimate of the original design without any changes to the equipment. On March 9, 2000, the NWCAA determined that new source review was not required as a result of this operational change.

On, December 8, 2000, the NWCAA issued revised OAC 526b allowing transfer of benzene concentrate between tanks to accommodate the need for conducting inspection and maintenance work on the tanks. On March 17, 2003, the NWCAA issued OAC 526c revising the list of tanks that were allowed to be used to storage benzene concentrate to the current list of Tanks #1 through 10, and 14.

On July 9, 2012, the NWCAA issued revised OAC 526d to improve formatting and to clean up the order for better incorporation into the air operating permit.

7. Crude Oil Tank #49

On June 2, 1997 the refinery proposed the construction of a 400,000 barrel, internal floating roof, crude oil storage Tank #49. Additional crude oil storage capacity was needed to reduce the number of marine tanker deliveries. Emissions from the tank would include VOC and TAP/HAP emissions and required controls specified under 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC. On August 13, 1997, the NWCAA issued OAC 620 approving the project. On

August 8, 2002, the NWCAA issued revised OAC 620a removing requirements that overlapped with other directly applicable requirements; i.e., 40 CFR 60 Subpart Kb, 40 CFR 63 Subpart CC, 40 CFR 60 Subpart GGG, 40 CFR 60 Subpart QQQ, and NWCAA 560 and 580.

On July 9, 2012, the NWCAA issued revised OAC 620b. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

In 2005 the tank was equipped with an internal steam heating coil to allow the flexibility to store heavier crude oils. The steam coil installation proposal was submitted with the Tank #40 project and approved by the NWCAA under OAC 897 issued November 15, 2004. On July 9, 2012, the NWCAA issued revised OAC 897a. Neither OAC contain any specifically applicable requirements for Tank #49.

Secondary seals were added to the tank after it was constructed.

8. Crude Oil Tank #40

On November 15, 2004, the NWCAA issued OAC 897 approving construction of a new, 365,000 barrel, internal floating roof crude oil storage Tank #40. The tank was needed in order to segregate, store and process a wider variety of crude oils because the production and supply of Alaskan North Slope Crudes, which historically had been the primary source of crude oil for the refinery, was declining. The tank was constructed and was put into operation October 2005. Typical of other storage tanks at the refinery, Tank #40 is equipped an internal floating roof with a mechanical shoe primary seal and rim mounted secondary seal. The tank is equipped with an internal steam coil to allow storage of heavy crudes. Tank #40 is subject to a number of federal and NWCAA requirements including 40 CFR 60 Subpart Kb, 40 CFR 63 Subpart CC, and NWCAA 560 and 580.

On July 9, 2012, the NWCAA issued revised OAC 897a. The revision was done to improve formatting and to clean up the order for better incorporation into the air operating permit.

9. Inspection and Maintenance

Seals are inspected in accordance with the frequencies specified in the underlying regulation. For IFR tanks, the annual inspection is visual through the fixed roof hatch with a comprehensive internal inspection being required once every five years for tanks with a single seal and once every ten years for tanks with double seals. The NWCAA is notified of all annual inspections and gap tests on a schedule developed by the refinery at the beginning of each calendar year. Adjustments to the schedule are be made at other times during the year as long as notices meet the 30/7 day advance notice requirements of the underlying rule. Advanced notices allow regulatory staff an opportunity to attend seal gap testing and internal inspections of tanks when they are degassed. Inspection and gap testing requirements are common to both 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC. Any seal gap measurements or other defects found during inspections which exceed the compliance thresholds are required to be corrected within 45 days (unless an extensions is used) and reported to the NWCAA on semiannual reports.

Internal and external floating roof tanks may not store volatile organic products that exceed a MTVP of 11.1 psia. Because the vapor pressure characteristics of crude oils and other non-finished products can vary considerably, their vapor pressures are sampled and tested to assure that they are maintained below 11.1 psia on an on-going basis. In addition some tanks have internal heaters that can increase storage temperatures above ambient. Temperature and vapor pressure records are kept by the facility and are available for inspection. Maximum true vapor pressures are calculated in using the methods in API Chapter 19.2 Evaporative Loss From Floating Roof Tanks (previously API Bulletin 2517).

10. Internal Floating Roof Tanks

Internal floating roof (IFR) tanks are also used to store high vapor pressure VOL products at the refinery. They are also used for store of a wider array of materials (e.g., slop oils, wastewater emulsions) when compared to the EFR tanks. IFR tanks use a fixed cone roof covering over the top of the tank along with an internal floating roof having at least a single seal system between the tank wall and floating roof cover. A second seal is not required by the underlying regulations because the fixed roof cover serves to reduce exposure of the floating roof thereby limiting fugitive VOC and HAP emissions. 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 requirements.

IFR tanks regulated under NSPS Subpart Kb are exempt from the requirements of Refinery MACT in accordance with the overlap provisions of 63.640(n). Although there are subtle differences in the underlying rules, compliance for IFR tanks can be summarized into the following conditions.

11. Internal Floating Roof Tank Monitoring Recordkeeping and Reporting Summary

Report as an upset, any time that stored VOL exceeds a true vapor pressure of 11.1 psia, determined on a monthly average. The report shall be made to the NWCAA within 12 hours of discovering the condition in accordance with NWCAA 340.

Quarterly, conduct a visual inspection of the tank to assure that openings are closed.

Annually, conduct a visual inspection of the floating roof through roof hatches to assure that:

There are no tears in the seal, the seal is not detached, there is no petroleum liquid accumulated on the floating roof and that the floating roof is resting on the VOL surface.

Once every ten years, empty and degas the tank and conduct an internal inspection to assure that:

The primary seal is either a mechanical shoe seal or a liquid-mounted seal that completely covers the annular space between the edge of the floating roof and the tank wall.

There are no defects in the floating roof, primary seal or secondary seal (if one is in place) and that are no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

If a mechanical shoe primary seal is in use, that it extends into the liquid and also extends at least 24 inches above the liquid surface.

That, except for openings that are automatic bleeder vents (vacuum breakers) and rim space vents, each opening in a non-contact floating roof has a projection below the liquid surface.

Sample wells are covered by a slotted fabric that covers at least 90% of the opening.

Each roof opening has a cover, lid or is otherwise sealed (except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells and stub drains).

Automatic bleeder vents are gasketed and closed except when the roof is being floated off, landed on, or resting on the roof leg supports.

Column wells have a flexible fabric sleeve seal or gasketed sliding cover.

Each ladder well has a gasketed sliding cover.

Notice of refill: Notify the NWCAA at least 30 days in advance that a tank will be refilled. If refilling is unplanned, 7 day advanced verbal notice followed immediately by a written notice is allowed.

Operational Records: Shall include tank #, type of VOL stored, its maximum true vapor pressure and dates of storage.

Repair of Defects/Failures: Any defect found during inspection and/or gap testing shall be repaired within 45 days or the tank emptied. If neither occurs, a 60 day extension past the initial 45 day period can be used if the refinery documents that no alternate storage capacity is available and that the repairs are completed as soon as possible.

Inspection Reports: On semiannual Refinery MACT Periodic Reports, submit information including the date of inspection, a list of defects/failures discovered and the nature and date of their repair. If a delay of repair (extension) is utilized, include documentation that alternate storage capacity is unavailable and information showing that repairs were completed as soon as possible.

12. Pressurized Vessels

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 limits stress on the vessel before its pressure limits are exceeded. In many cases PRD's are vented to the atmosphere, however, in some cases they are routed through a closed vent system to the flares.

4 AIR OPERATING PERMIT ADMINISTRATION

In developing the AOP for the BP Cherry Point Refinery, 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 SOB and AOP.

4.1 Permit Assumptions

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

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.

2. "Narrative" Orders of Approval to Construct (OAC)

The following Order of Approval to Construct (OAC) permits issued by the NWCAA under their 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 1995. Because they are narrative in content, they do not contain any specific conditions that are considered specifically applicable requirements under Title V.

- OAC 116 issued September 17, 1973 – Storage Tanks #47 and #48
- OAC 120 issued October 12, 1973 – Three crude storage tanks (not built)
- OAC 148 issued November 20, 1974 - HC 1st Stage Frac Reboiler Preheater
- OAC 149 issued November 20, 1974 - HC 2nd Stage Frac Reboiler Preheater
- OAC 159 issued May 20, 1975 – Crude Heater Preheater
- OAC 246 issued April 10, 1980 - New baghouse at #1 & 2 Calciner
- OAC 253a issued May 15, 1989 – New crude storage Tank #50
- OAC 272 issued April 17, 1990– Wastewater Treatment Plant covers
- OAC 281 issued August 8, 1990 – Crude to Condensate Project
- OAC 283 issued May 15, 1990 - Coker Olefin Upgrade Project (COUP)
- OAC 290 issued June 14, 1984 - New elemental sulfur storage tank
- OAC 293 issued September 13, 1984 - Two new calcined coke silos
- OAC 299 issued December 19, 1984 - #3 Calciner (permitted under PSD)
- OAC 306 issued November 14, 1984 – New calcined coke loadout facility
- NWCAA Letter dated December 19, 1988 - Two new baghouses to control dust at the coke loadout facility
- OAC 371a issued May 1, 1992 – New 31,500 barrel storage Tank #71.
- OAC 453b issued November 23, 1993 – New 200,000 barrel storage Tank #24

3. “Superseded Requirements”

Requirements in permits (OAC’s or PSD permits) that have been superseded are not considered applicable requirements and are not included in the AOP.

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. 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. For Washington Administrative Code (WAC) regulations, the date listed in parenthesis in the air operating permit represents the State Effective date. For 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 or PSD permit represents the issuance date of that new source review construction permit. For a federal rule, the date is the rule’s most recent promulgation date.

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

In the case of an OAC or PSD permit, the date in parenthesis represents the issuance date of that order or NSR permit.

5. Future Requirements

Applicable requirements that have been promulgated with future effective compliance dates may be included as applicable requirements in the permit. 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 permit.

6. Compliance Options

The BP Cherry Point refinery did not request emissions trading provisions or specify more than one operating scenario in the air operating permit application; therefore the permit does not address these options as allowed under WAC 173-401-650. This permit does not condense overlapping applicable requirements (streamlining) nor does it provide any alternative emission limitations.

4.2 Permit Elements

The 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 - Specific Applicable Common Requirements
- Section 7 - Inapplicable Requirements

Sections 2 through 6 include citations to applicable requirements (e.g., regulations and OACs) and a summary of that requirement. In addition Sections 3 through 6 include the monitoring, recordkeeping and reports (MR&R) obligations for each requirement.

1. Permit Information and Attest Pages.

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

2. Emission Unit Identification

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, and other related comments. The emission unit identification number commonly used at the refiner is the process unit/area number followed by the equipment number.

3. Standard Terms and Conditions

Sections 2 and 3 entitled "Standard Terms and Conditions" contain administrative requirements and prohibitions that do not 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 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 unit.

The Standard Terms and Conditions section of the permit include general provision for both federal new source performance standards (NSPS) and national emission standards for hazardous air pollutants (NESHAP).

4. Generally Applicable Requirements

Section 4 entitled "Generally Applicable Requirements" identifies requirements that apply broadly to the refinery. 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 Sections 4 and 5, the first column lists the permit term number and pollutant or type of requirement. The permit terms are numbered consecutively so that the

reader may locate a listed requirement. 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 and is not intended to be a legal requirement as it is for descriptive purposes only. The last column, lists the monitoring, recordkeeping and reporting (MR&R) requirements. The MR&R is a summary of the underlying requirement cited in the “citation” column and is not directly enforceable. However, when there is text in the MR&R column that states “Directly Enforceable”, all text below that statement has been added by the NWCAA as part of the agency’s gap-filling authority and these additional requirements are enforceable. The agency uses gap-filling when the cited underlying requirement (e.g., regulation, OAC) does not provide adequate monitoring, recordkeeping and/or reporting methods to demonstrate compliance with the applicable requirement. In these cases, the NWCAA uses its authority under WAC 173-401-615(b) to gap-fill with adequate MR&R.

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.

5. Specifically Applicable Requirements

Section 5 entitled “Specifically Applicable Requirements” lists requirements that are specific to the individual emission units within the refinery. Each table in Section 5 represents a refinery process unit or area. Within each table emission units (EU) are presented in order of their size. As a general practice heaters are presented first, followed by vents, drains and lastly fugitive emissions components. For each emission unit, permit terms are generally presented in the following manner; general, visual emissions (VE), particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), nitrogen oxides (NOX), carbon monoxide (CO), volatile organic compounds (VOC) and hazardous air pollutants (HAP).

The emission limitations and monitoring, recordkeeping and reporting 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.

The refinery uses CEMs in many of the heater and boiler stacks to continuously monitor the concentration of various air pollutants. Pollutants concentration values are also used to determine compliance with mass emission limits such as lb/hour or tons per year limits given flue gas flow rates which are often calculated based on the amount of refinery flue gas that is combusted. If a CEM is not required, the source is often required to conduct periodic stack testing to determine emission levels. In these cases compliance demonstration is relatively straightforward because CEMs and stack testing provides emissions values that are based on EPA approved monitoring methods and testing procedures.

Particulate matter is not usually monitored by either a CEM or through stack testing. In many cases, periodic visual observations are used as a surrogate to determined compliance with a particulate matter emission limit. This is appropriate because the refinery burns only gaseous fuels in its heaters and boilers, which are inherently low particulate emitters, and due to the fact that visual emissions from these stacks is commonly not visible.

6. Specifically Applicable Common Requirements

Section 6 entitled “Specifically Applicable Common Requirements” includes:

Ongoing compliance with visual emissions standards (i.e., 20% opacity under NWCAA 451 and/or more stringent NSR conditions) are qualitatively assessed by conducting periodic visual observations of the refinery stacks. Unless otherwise specified in the term, the MR&R for visual emissions is found in Section 6 of the permit which is called “Specifically Applicable Common

Requirements". Under Section 6.1 the permittee must periodically conduct visual observations of the refinery stacks. If visible emissions are observed, the permittee must reduce to zero, or take certified opacity readings using Method Ecology 9A within 24 hours of observing the visual emissions. Visual emissions are considered to be in excess of the applicable opacity limit if a certified reading is not taken. Some emission units have specifically applicable requirements that require more frequent visual observations than those of Section 6.1.

Visual observation monitoring under 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 of the emissions unit.

Section 6 includes requirements that apply to a number of emission units located throughout the refinery under OAC 211c. Section 6 also includes the leak detection and repair (LDAR) requirements of 40 CFR 60 Subpart VV and Subpart VVa that apply to equipment components located at a variety of process units.

7. Compliance Assurance Monitoring (CAM)

The 40 CFR Part 64 CAM rule requires owners and operators to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. If owners and operators of these facilities find that their control equipment is not working properly, the CAM rule requires them to take action to correct any malfunctions and to report such instances to the appropriate enforcement agency (i.e., State and local environmental agencies). Additionally, the CAM rule provides some enforcement tools that will help State and local environmental agencies require facilities to respond appropriately to the monitoring results and improve pollution control operations.

The CAM rule applies to each Pollutant Specific Emissions Unit (PSEU) when it is located at major source that is required to obtain Title V, Part 70 or 71 permit and it meets all of the following criteria:

- be subject to an emission limitation or standard, and
- use a control device to achieve compliance, and
- have **potential pre-control** emissions that exceed or are equivalent to the major source threshold.

Please note that the term "PSEU" means an emissions unit considered separately with respect to each regulated air pollutant. Also the term "control device" means equipment, other than inherent process equipment, that is used to destroy or remove air pollutants prior to discharge to the atmosphere. The term "control device" does not include passive methods such as lids or seals or inherent process equipment provided for safety or material recovery.

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

- post – 11/15/90 NSPS or NESHAP standards, since those standards have been and will be designed with monitoring that provides a reasonable assurance of compliance;
- stratospheric ozone protection requirements under Title VI of the act;
- acid rain program requirements;
- emission limitations or standards or other requirements that apply solely under an approved emissions trading program;
- emissions cap that meets requirements of 70.4(b)(12) or 71.6(a)(13);

- emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 40 CFR 64.1;
- certain municipally-owned utility units, as defined in 40 CFR 72.2.
- Please note that the 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 limits) apply to the emissions unit.

Part 64 requires permits to specify at a minimum:

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

BP is a major source, so the CAM rule can apply. Based upon potentials to emit the CAM rule applies at the following emission units:

Table 4-1 Emission Units and Pollutants Subject to CAM

Pollutant-Specific Emission Unit	Description	Control Device	Pollutant
Calciner, Stack #1	#1 & #2 Calciner Hearth	WESP	PM ₁₀
Calciner, Stack #1	#1 & #2 Calciner Hearth	WESP	H ₂ SO ₄
Calciner, Stack #2	#3 Calciner Hearth	WESP	PM ₁₀
Calciner, Stack #2	#3 Calciner Hearth	WESP	H ₂ SO ₄
Calciner	Coke Silos and Loading	Bag House	PM ₁₀
Delayed Coker	North and South Charge Heaters	Flue Gas Recirculation	NOX

Table 4-2 Emission Units and Pollutants not subject to CAM

PSEU Designation	Unit Description & Control Device	Pollutant & Reasons for Non Applicability
Primary Crude/ Vacuum Process Area	<ul style="list-style-type: none"> • Crude Heater • North Vacuum Heater • South Vacuum Heater 	These units do not have control devices.
Naphtha HDS and Reformer Units	<ul style="list-style-type: none"> • #1 Reformer Heater • #2 Reformer Heater • Naphtha HDS Charge Heater • Naphtha HDS Stripper Reboiler 	These units have no control device
Hydrocracker	<ul style="list-style-type: none"> • 1st Stage Fractionator Reboiler • 2nd Stage Fractionator Reboiler • R-1 Hydrocracker Reactor Heater • R-4 Hydrocracker Reactor Heater 	These units have no control device

PSEU Designation	Unit Description & Control Device	Pollutant & Reasons for Non Applicability
Delayed Coker	<ul style="list-style-type: none"> • North Coker Heater • South Coker Heater 	SO ₂ , CO – no control devices for these pollutants
Diesel HDS	<ul style="list-style-type: none"> • #1 Diesel HDS Charge Heater • #1 Diesel HDS Stabilizer Reboiler • #2 Diesel HDS Charge Heater 	These units have no control device
Hydrogen Plant	<ul style="list-style-type: none"> • North Heater • South Heater 	These units have no control device
Boilers and Cooling Towers	<ul style="list-style-type: none"> • Utility Boiler #1 • Utility Boiler #3 • Utility Boiler #4 • Utility Boiler #5 • Cooling Tower #1 • Cooling Tower #2 	These units have no control device
Flares	<ul style="list-style-type: none"> • Flare Gas Recovery • Low Pressure Flare • High Pressure Flare 	These units have no control device
Sulfur Complex	<ul style="list-style-type: none"> • #1 TGU Stack • #2 TGU Stack 	These units are subject to both NSPS and MACT standards and are equipped with CEMS.
Wastewater Treatment Plant	<ul style="list-style-type: none"> • API Separators • Slop Oil • equalization and recovered oil tanks 	These units are subject to MACT.
Storage and Handling	<ul style="list-style-type: none"> • Tank Farm • Butane/Pentane Spheres 	These units have no control device
Shipping, Pumping and Receiving	<ul style="list-style-type: none"> • Marine Dock –Use Dock Thermal Oxidizer as control device • Truck Rack- Use Truck Rack Thermal Oxidizer as control device • Rail Car Loading • LPG Loading Racks 	These units are subject to NSPS and MACT standards.
LEU/LPG	<ul style="list-style-type: none"> • Light End Unit (LEU) • Liquefied Petroleum Gas 	This unit has no control device
Isomerization	<ul style="list-style-type: none"> • IHT Heater 	This unit has no control device
Calciner	<ul style="list-style-type: none"> • Hearths #1, 2, & 3 	VOC, NO _x - No control device for these pollutants SO ₂ – Units equipped with CEMS

All of the BP pollutant specific emission units are classified as “other pollutant-specific emission units.” An “other pollutant-specific emission unit” is one that has a potential to emit more than 100 tons per year of a pollutant *without* the control device, but has the potential to emit less than 100 tons per year of that same pollutant *with* the control device. The CAM rule

requirements apply to “other pollutant-specific emission units” upon air operating permit renewal.

BP submitted a CAM plan with its air operating permit renewal application. The plan was reviewed by the Northwest Clean Air Agency and found to satisfy the requirements of 40 CFR 64. The CAM plan was subsequently incorporated into the air operating permit in the appropriate portions of Section 5.

8. Inapplicable Requirements

WAC 173-401-640 requires that the permitting authority to 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. The basis for each determination of inapplicability is included.

9. Insignificant Emissions Units

Categorically exempt emissions units listed in WAC 173-401-532 are present at the refinery. These emission units have very low, if any, emissions associated with their use and are therefore considered insignificant by regulation and not included in the air operating permit.

4.3 Public Docket

Copies of BP Cherry Point Refinery's Air Operating Permit application and technical support documents are available at the following location:

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

4.4 Public Comments and NWCAA Responses

1. November 2012 Comments (AOP 015M1)

BP Cherry Point Refinery provided comments on the Draft Air Operating Permit (AOP) and Statement of Basis (SOB) via an email received on November 25, 2012 from Environmental Superintendent Jeff Chalfant. All comments from BP were addressed by the NWCAA as summarized below.

Comments Regarding the Draft AOP

Comment 1:

"Control Devices and CEMS: To be consistent with the NWCAA format in Section 1, the control devices and CEMS currently associated with a source were added in the comments section."

Response 1:

For the most part the suggested changes were accepted and the AOP revised accordingly.

Comment 2:

"Heater Duties: Heater duties obtained from Confidential Business Information submitted with the consent decree between BP and the EPA should be removed."

Response 2:

The AOP contains no information on heater duties that were obtained from Confidential Business Information submitted with the consent decree between BP and the EPA.

Comment 3:

"Source Testing: Certain source test methods were added for correction and clarification to better reflect the current testing methodologies used for the specific sources. These clarifications and corrections should aid NWCAA in reviewing future Source Test Plans."

Response 3:

With the following exceptions, the suggested revisions were accepted because they add accuracy and/or clarification to the AOP.

Permit term 2.1.10 was not revised as suggested because cited regulation is dated 2/8/89 and is paraphrased correctly.

Permit term 3.1.7 was not revised as suggested because it is accurate with regard to the text in the current rule. EPA's TTN notes that Method 3A was inadvertently left out of the regulation cited by the term. However, the permit term accommodates needed flexibility by stating that the compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary.

Permit terms 5.3.7, 5.3.25, 5.4.4, 5.4.7, 5.4.8, 5.5.8, 5.5.17, 5.6.7, 5.7.8, 5.7.11, 5.7.13, 5.8.8, 5.12.5 and 5.12.17 were not revised as suggested by adding EPA Method 19 to the list of prescribed test methods. Method 19 provides an emission factor in lb/MMBtu that serves as a practical method for estimating ongoing emission rates for a given pollutant. However, its accuracy is limited due to variability in the heat content and Fd value of refinery fuel gas, and the uncertain accuracy of metering systems used to monitor fuel consumption. Compliance with a mass emission limit, such as lb/hour, is best demonstrated using EPA Methods 1, 2 and 4 in conjunction with the pollutant specific method, such as Method 7E for NOx. Methods 1, 2 and 4 provide a direct measurement of the exhaust gas flow rate in the stack during source testing. In contrast Method 19 can introduce errors through assumptions about the heat content and Fd value of the fuel, and the accuracy of the fuel gas metering system.

Method 19 has not been added to these permit terms because the underlying requirements cited in each term does not explicitly prescribe the use of Method 19. If the refinery submits source test plans that include the use of Method 19 in lieu of Methods 1, 2 and 4, the agency will consider its acceptability during the source test plan review and approval process specified in Appendix A of the NWCAA Regulation.

Permit terms 5.7.5 and 5.10.9 were not revised as requested by adding EPA Other Test Methods (OTM) 27 and 28. OTM 27 and 28 are listed as prescribed test methods in the underlying requirement of OAC 1064. However, this construction approval permit was issued prior to OTM 27 and 28 being superseded when these test methods were promulgated into the currently approved test methods 201A and 202, respectively.

Permit term 5.12.24 was not revised as requested by adding flexibility to the long term test frequency of the boilers. The term is consistent with the underlying test frequency requirement as stated in the cited PSD permit.

Permit term 5.15.4 was not revised as requested by replacing the referenced test method with 40 CFR 60 Method 2. Method 2 measures velocity and volumetric flow and is not an appropriate method for determining the VOC/HAP control as cited by the term.

Comment 4:

“LDAR: Equipment leak citations have been corrected to the appropriate rule citation and the associated descriptions have been modified to agree with the appropriate citation.”

Response 4:

All requested permit terms have been revised as suggested for clarity and accuracy except as follows. Permit term 6.3.1 was not revised because the suggested revisions are in the AOP under term 6.3.8 that is referenced in 6.3.1. Permit term 6.3.2 was not revised as suggested because the suggested text is inconsistent with the text in the cited regulation.

Comment 5:

“Boiler MACT: The Federal Register FR 2012-20642 dated September 19, 2012 contained the finalized version of 40 CFR 63 Subpart DDDDD. Based on that information, BP has suggested Monitoring, Reporting and Recordkeeping language to be added to the AOP.”

Response 5:

The Federal Register dated September 19, 2012, does not contain any information related to the Boiler MACT. The NWCAA has included permit terms for 40 CFR 63 Subpart DDDDD subject emission units and these terms appropriately state that monitoring, recordkeeping and reporting requirements are undetermined at the time of permit issuance.

Comment 6:

"Permits: Air load testing at Calciner #1 and #2 in Permit Term 5.11.7 was deleted as that is only required for Calciner #3."

Response 6:

Permit term 5.11.7 was not revised as suggested because the Calciner No. 1 (Hearths # 1 & #2) monitoring plan dated October 7, 1999, prescribes air load testing.

Comment 7:

"Permits: Permit Term 5.13.4 contains too many conditions from Subpart Ja and BP recommends that it be separated into two separate conditions for clarity and recordkeeping and reporting purposes."

Response 7:

All permit terms that include citations to 40 CFR 60 Subpart Ja were reviewed and revised as needed for clarity and accuracy.

Comment 8:

"Permits: Internal floating roof tanks 72, 73 and 74 have had additional seals installed to accommodate the storage of jet fuel. These changes should have been added to OAC527c. Jet fuel was added to Permit Term 5.18.18."

Response 8:

Permit term 5.18.18 was not revised as suggested because the term is consistent with the requirement in the cited OAC.

Comment 9:

"Permits: Permit Term 6.1 has language that conflicts with the individual source opacity limits. BP has suggested language in the AOP comment."

Response 9:

Permit term 6.1 was not revised as suggested because the term is written appropriately.

Comments Regarding the Draft SOB

Comment 10:

"Regulatory History: The Regulatory Order "PM Bubble" was superseded by OAC211c. This correction was made in the Statement of Basis."

Response 10:

The SOB was revised reflecting the fact that the "PM Bubble" order was superseded by OAC 689b issued September 18, 2012.

Comment 11:

"NSPS Subpart J: Additional clarification on the Subpart J fuel gas exemption for the marine loading and truck loading vapors was added to the Statement of Basis."

Response 11:

The SOB was revised accordingly.

2. June 2014 Comments (AOP 015R1M1)

BP Cherry Point Refinery provided comments on the Draft Air Operating Permit (AOP) and Statement of Basis (SOB) via a letter received on June 5, 2014 from Scott Inloes, BP Senior Environmental Engineer. All comments from BP were addressed by the NWCAA as summarized below.

Comments Regarding the Draft AOP

Comment 1:

Pg. 2 - Responsible Official will be Bob Allendorfer.

Response 1:

BP provided additional information to show that Mr. Allendorfer meets the definition of a responsible official. Change made as requested.

Comment 2:

Pg. 130 – Permit Term 5.7.14 for DHDS#3.

- Change compliance date for new sources in Description column: “Comply with 40 CFR 63 Subpart DDDDD at major sources of HAPs for new boilers and process heaters upon startup”.
- State that Permit Term 6.5.3 is not applicable (Energy Assessment is for existing sources only): “Comply with Section 6.5, except for Permit Term 6.5.3”.

Response 2:

The description of permit term 6.5.3 of the AOP (energy assessment) states that the energy assessment only applies to existing units. The #3 DHDS is a new unit under the MACT, so it doesn't need to be included in the energy assessment. To add clarity, the following changes were made to permit term 5.7.14:

- Citation for the new unit compliance date was added.
- Description was modified to include the compliance date for a new unit.
- Monitoring was modified to state that the #3 DHDS must comply with section 6.5, except for 6.5.3, which doesn't apply.

Section 2.2(7) of the Statement of Basis was also updated to state “The energy assessment is required only for existing units.”

Comment 3:

Pg. 131 – Permit Term 5.7.19 PSD Notifications

- Drop this requirement because the notifications have been submitted. Put Reserved in the description section to avoid confusion.

Response 3:

AOP term 5.7.19 (PSD-10-01 Conditions 15) requires BP to provide initial notifications of commencing construction and firing. These one-time notifications were received on 7/8/11 and 4/26/13. Since Condition 15 doesn't have any on-going requirements and the one-time requirements have been completed, this condition is not included in the AOP. This change was also documented in Statement of Basis Section 3.6.3.

Comment 4:

Pg. 131 – Permit Term 5.7.21 PSD Start construction

- Drop the requirement because construction has been completed. Put Reserved in the description section to avoid confusion.

Response 4:

AOP term 5.7.21 (PSD-10-01 Conditions 19) states that construction must begin with 18 months of receipt of the final PSD and must not be discontinued for a period of 18 or more months. The unit has been constructed. Therefore, this condition is now obsolete and will be removed as requested. This change was also documented in Statement of Basis Section 3.6.3.

Comment 5:

Pg. 145 – Permit Term 5.10.19 for Hydrogen SMR #2.

- Change compliance date for new sources in Description column: “Comply with 40 CFR 63 Subpart DDDDD at major sources of HAPs for new boilers and process heaters upon startup”.
- State that Permit Term 6.5.3 is not applicable (Energy Assessment is for existing sources only): “Comply with Section 6.5, except for Permit Term 6.5.3”.

Response 5:

The description of permit term 6.5.3 of the AOP (energy assessment) states that the energy assessment only applies to existing units. The #2 SMR furnace is a new unit under the MACT, so it doesn't need to be included in the energy assessment. To add clarity, the following changes were made to permit term 5.10.19:

- Citation for the new unit compliance date was added.
- Description was modified to include the compliance date for a new unit.
- Monitoring was modified to state that the unit must comply with section 6.5, except for 6.5.3, which doesn't apply.

Section 2.2(7) of the Statement of Basis was also updated to state “The energy assessment is required only for existing units.”

Comment 6:

Pg. 147 – Permit Term 5.10.30 for #2 H2 flare

- Change the compliance require data to indicate that it has be meet. ~~Compliance shall be achieved by no later than November 11, 2015.~~ The first Flare Management Plant was submitted to EPA in March 2013.

Response 6:

A copy of the flare management plan was received by NWCAA on 3/19/13. The plan stated that the flare was in compliance at start-up. The requirement to write a plan, submit it to the administrator, and achieve initial compliance has been satisfied. These requirements were removed from term 5.10.30 of the AOP. This information was also documented in Section 3.9.2 of the Statement of Basis.

Comment 7:

Pg. 148 – Permit Term 5.10.33 & 34 for #2 H2 plant

- Drop the 18 months to start construction and notifications. All the requirements have been meet. Put Reserved in the description section to avoid confusion.

Response 7:

- AOP term 5.10.33 (PSD-10-01 Conditions 19) states that construction must begin with 18 months of receipt of the final PSD and must not be discontinued for a period of 18 or more months. The unit has been constructed. Therefore, this condition is now obsolete and will be removed as requested. This change was also documented in Statement of Basis Section 3.9.2.
- AOP term 5.10.34 (PSD-10-01 Conditions 15) requires BP to provide initial notification of commencing construction and firing. These one-time notifications were received on 7/8/11 and 4/26/13. Since Condition 15 doesn't have any on-going requirements and the one-time

requirements have been completed, this condition is not included in the AOP. This change was also documented in Statement of Basis Section 3.9.2.

Comment 8:

Pg. 163 – Permit Term 5.12.21 & 22 The conditions have been dropped from the permit.

- Put Reserved in the description section to avoid confusion.

Response 8:

Change made as requested.

Comment 9:

Pg. 164 – Permit Term 5.12.26 The condition has been dropped from the permit.

- Put Reserved in the description section to avoid confusion.

Response 9:

Change made as requested.

Comment 10:

Pg. 165 – Permit Term 5.12.30 The condition has been dropped from the permit.

- Put Reserved in the description section to avoid confusion.

Response 10:

Change made as requested.

Comment 11:

Pp. 235 – Section 6.1 states the monitoring, recordkeeping and reporting requirements for visual emissions from ~~combustion~~ emissions unit and at the refinery. This clarification would allow for monitoring for non-combustion devices.

Response 11:

The intent of Section 6.1 is to be used for both combustion and non-combustion units. Change made as requested.

Comment 12:

Permit Term 6.5.1.

- **Citation column** – missing citations: § 63.7540(a)(13): "If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup."; § 63.7545(e)(1): "A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded nonhazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration."; § 63.7545(e)(6): "A signed certification that you have met all applicable emission limits and work practice standards."; § 63.7545(e)(7): "If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report." § 63.7560: "Record retention"
- **Description column** - Add due date for tune-ups for new units with a continuous oxygen trim system: "Conduct a tune-up of the process heater every 5 years. The initial

tune-up shall be completed by January 31, 2016 for existing units, and within 61 months of startup for new units. Subsequent tune-ups shall be conducted no more than 61 months after the previous tune-up. "

- Monitoring, Recordkeeping and Reporting column** – Add in following language: "Submit a signed certification in the Notification of Compliance Status (NCS) in accordance with AOP 3.3.10 and 3.3.11 that indicates a tune-up was completed. Include a statement in the NCS, as applicable, "This facility complies with the initial tune-up according to the procedures in 63.7540(a)(10)(i) through (iv)." Submit an initial 5-year compliance report by January 31, 2021 for existing sources, and by July 31 that is five calendar years after the startup date for new sources. Subsequent 5-year compliance reports are to be submitted by Jan. 31 of the year following the 5-year reporting period. If available, the compliance reports shall also be submitted electronically via CEDRI (www.epa.gov/cdx). The compliance report shall include, among other things, the date of the most recent tune-up and burner inspection; if applicable, a statement that no deviations occurred; and be certified by the Responsible Official."

Response 12:

Citation Column: The citations for 40 CFR 63.7540(a)(13) and 63.7545(e)(1) were added to the AOP as suggested. However, the comment also suggested adding 63.7545(e)(6) and (e)(7). These citations were not added because these requirements are not applicable per 40 CFR 63.7545(e), which states "If you are not required to conduct an initial compliance demonstration as specified in 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8)." Because the units at BP qualify as Gas 1 units, the facility does not need to provide an initial compliance demonstration as per 40 CFR 63.7530(a). Therefore, only 63.7545(e)(1) and (e)(8) apply, and not (e)(6) or (e)(7).

Description and monitoring columns: the draft AOP that went out for 30-day comment already included the requested language (see screen shot below). Therefore, no change was made.

Permit Term	Citation	Description	Monitoring, Recordkeeping and Reporting
6.5.1	40 CFR 63 Subpart DDDDD 63.7500(a), (e), Table 3 Line 1, 7505(a), 7510(e), 7515(d), 7530(d), 7540(a)(10), (a)(12) & (b), 7545(a) & (e)(8)(i), 7550(a), (b), Table 9, (c)(1), (c)(5)(i)-(iv), (xiv), & (xvii), (h)(3), 7555(a) (1/31/13)	<u>Tune-Up - units with Continuous Oxygen Trim</u> Conduct a tune-up of the process heater every 5 years. The initial tune-up shall be completed by January 31, 2016 for existing units, and upon startup for new units. Subsequent tune-ups shall be conducted no more than 61 months after the previous tune-up. Conduct tune-up and maintain reports as per 40 CFR 63.7540(a)(10)(i)-(vi).	Submit a signed certification in the Notification of Compliance Status (NCS) in accordance with AOP Term 3.3.10 and 3.3.11 that indicates a tune-up was completed. Include a statement in the NCS, as applicable, "This facility complies with the initial tune-up according to the procedures in 63.7540(a)(10)(i) through (iv)." Submit a compliance report every five calendar years. If available, the compliance reports shall also be submitted electronically via CEDRI (www.epa.gov/cdx). The compliance report shall include, among other things, the date of the most recent tune-up and burner inspection; if applicable, a statement that no deviations occurred; and be certified by the Responsible Official.

Comment 13:

Permit Term 6.5.2.

- Citation column** - missing citations: § 63.7540(a)(13): "If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup."; § 63.7545(e)(1): "A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded nonhazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration."; § 63.7545(e)(6): "A signed certification

that you have met all applicable emission limits and work practice standards.”; § 63.7545(e)(7): “If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.”; § 63.7560: “Record retention”

- **Description column** - Add due date for tune-ups for new units without a continuous oxygen trim system “Conduct a tune-up of the process heater annually. The initial tune-up shall be completed by January 31, 2016 for existing units, and within 13 months of startup for new units. Subsequent annual tune-ups shall be conducted no more than 13 months after the previous tune-up. Conduct tune-up and maintain as per 40 CFR 63.7540(a)(10)(i)-(vi).”
- **Monitoring, Recordkeeping and Reporting column** – Add in following language: “Submit a signed certification in the Notification of Compliance Status (NCS) in accordance with AOP Term 3.3.10 and 3.3.11 that indicates a tune-up was completed. Include a statement in the NCS, as applicable, “This facility complies with the initial tune-up according to the procedures in 63.7540(a)(10)(i) through (iv).” Submit an initial annual compliance report by January 31, 2017 for existing sources, and by July 31 that is one calendar year after the startup date for new sources. Subsequent annual compliance reports are to be submitted by Jan. 31 of the year following the annual reporting period. If available, the compliance reports shall also be submitted electronically via CEDRI (www.epa.gov/cdx). The compliance report shall include, among other things, the date of the most recent tune-up and burner inspection; if applicable, a statement that no deviations occurred; and be certified by the Responsible Official.”

Response 13:

Citation Column: The citations for 40 CFR 63.7540(a)(13) and 63.7545(e)(1) were added to the AOP as suggested. However, the comment also suggested adding 63.7545(e)(6) and (e)(7). These citations were not added because these requirements are not applicable per 40 CFR 63.7545(e), which states “If you are not required to conduct an initial compliance demonstration as specified in 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).” Because the units at BP qualify as Gas 1 units, the facility does not need to provide an initial compliance demonstration as per 40 CFR 63.7530(a). Therefore, only 63.7545(e)(1) and (e)(8) apply, and not (e)(6) or (e)(7).

Description and monitoring columns: the draft AOP that went out for 30-day comment already included the requested language (see screen shot below). Therefore, no change was made.

6.5.2	40 CFR 63 Subpart DDDDD 63.7500(a), (e), Table 3 Line 3, 7505(a), 7510(e), 7515(d), 7530(d), 7540(a)(10) & (b), 7545(a) & (e)(8)(i), 7550(a), (b), Table 9, (c)(1), (c)(5)(i)-(iv), (xiv), & (xvii), (h)(3), 7555(a) (1/31/13)	<u>Tune-Up – units without Continuous Oxygen Trim</u> Conduct a tune-up of the process heater annually. The initial tune-up shall be completed by January 31, 2016 for existing units, and upon startup for new units. Subsequent annual tune-ups shall be conducted no more than 13 months after the previous tune-up. Conduct tune-up and maintain as per 40 CFR 63.7540(a)(10)(i)-(vi).	Submit a signed certification in the Notification of Compliance Status (NCS) in accordance with AOP Term 3.3.10 and 3.3.11 that indicates a tune-up was completed. Include a statement in the NCS, as applicable, “This facility complies with the initial tune-up according to the procedures in 63.7540(a)(10)(i) through (iv).” Submit a compliance report every calendar year. If available, the compliance reports shall also be submitted electronically via CEDRI (www.epa.gov/cdx). The compliance report shall include, among other things, the date of the most recent tune-up and burner inspection; if applicable, a statement that no deviations occurred; and be certified by the Responsible Official.
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Comment 14:

Permit Term 6.5.3.

Citation column - missing citations: § 63.7545(e)(1): “A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of

this chapter, whether the fuel(s) were a secondary material processed from discarded nonhazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.”; § 63.7545(e)(6): “A signed certification that you have met all applicable emission limits and work practice standards.”; § 63.7545(e)(7): “If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.”; § 63.7560: “Record retention”.

Response 14:

The citation and requirement to include information required by 40 CFR 63.7545(e)(1) in the Notification of Compliance was added to the AOP as suggested. The comment also suggested adding 63.7545(e)(6) and (e)(7). These citations were not added because these requirements are not applicable per 40 CFR 63.7545(e), which states “If you are not required to conduct an initial compliance demonstration as specified in 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).” Because the units at BP qualify as Gas 1 units, the facility does not need to provide an initial compliance demonstration as per 40 CFR 63.7530(a). Therefore, 63.7545(e)(6) and (e)(7) don’t apply.

Comment 15:

Permit Term 6.5.4. - Although these requirements apply today, EPA has indicated that they will not be required for Other Gas 1 sources when they issue technical corrections to the rule.

Response 15:

Thank you for the comment. A change cannot be made to the AOP until after EPA officially issues the technical correction. NWCAA is open to modifying the AOP when the change is finalized by EPA. Please submit a modification request at that time.

Comments Regarding the Draft SOB

Comment 1:

Pg. 2 - Responsible Official will be Bob Allendorfer.

Response 1:

BP provided additional information to show that Mr. Allendorfer meets the definition of a responsible official. Change made as requested.

Comment 2:

Pg. 22 - Add in following language: “Subpart DDDDD does not require any pollutant specific emission limits for existing or new heaters and boilers in the “Gas 1” category. Instead, the rule requires work practice standards that include annual “tune-ups” as defined in §63.7540(a)(10) and a one-time energy assessment for existing sources performed by a qualified energy assessor. The refinery is required to maintain records of the amount of fuel used in each heater or boiler, the dates and hours that it operated, startup and shutdown events, and the date and result of each tune-up and energy assessment performed under the rule.”

Response 2:

The requested language is already included in Section 2.2(7) of the Statement of Basis which went out for 30-day public comment (see screen shot below). To keep the Statement of Basis streamlined, this language was not repeated. No change made.

Subpart DDDDD does not require any pollutant specific emission limits for existing or new heaters and boilers in the "Gas 1" category. Instead, the rule requires work practice standards that include "tune-ups" as defined in §63.7540(a)(10) and a one-time energy assessment performed by a qualified energy assessor. The refinery is required to maintain records of the amount of fuel used in each heater or boiler, the dates and hours that it operated, startup and shutdown events, and the date and result of each tune-up and energy assessment performed under the rule.

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4.5 Definitions and Acronyms

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

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

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

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

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

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

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

ACO	Agreed Compliance Order
AIRS	Aerometric Information Retrieval System
AMP	Alternative Monitoring Plan
AOP	Air Operating Permit
ASIL	Acceptable Source Impact Level
ASTM	American Society for Testing and Materials
Avjet	aviation jet fuel
BACT	best available control technology
BHU	Butadiene Hydrogenation Unit
Btu	British thermal unit
BQ6	Benzene waste Quantity under 6 Mg/yr (wastewater)
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEM	continuous emission monitor
CEMS	continuous emission monitoring system
CI-ICE	Compression Ignition – Internal Combustion Engine
CFM	cubic feet per minute
COM	continuous opacity monitor
CFR	Code of Federal Regulations
CPMS	continuous parameter monitoring system
CRU	Catalytic Reforming Unit
DAF	Dissolved Air Flootation (wastewater)
DHDS	Diesel Hydrodesulfurization Unit
DCU	Delayed Coking Unit
EFR	External Floating Roof (tank)
EPA	United States Environmental Protection Agency
ERC	Emission Reduction Credit

ESP	Electrostatic Precipitator
FCAA	Federal Clean Air Act
FCCU	Fluid Catalytic Cracking Unit
FGR	Flue Gas Recirculation
HAP	Hazardous Air Pollutants
HC	hydrocarbon
HHV	Higher Heating Value (heat content of fuel)
HON	Hazardous Organic NESHAP
HTU	Hydrotreater Unit
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid
hp	horsepower, brake
HRSG	heat recovery steam generator
HSR	Heavy Straight Run
IFR	Internal Floating Roof (tank)
IHT	Isomerization Process Heater
ISO	International Standards Organization
kPa	kilopascals (10 ³ pascals pressure)
LDAR	leak detection and repair
LNB	Low-NOx Burner
LEL	lower explosive limit
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
MPS	meters per second
MR&R	monitoring, recordkeeping and reporting requirements
MTVP	maximum true vapor pressure
NIST	National Institute of Standards and Technology
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOC	Notice of Construction
NOx	oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
NWCAA	Northwest Clean Air Agency
O ₂	oxygen
OAC	Order of Approval to Construct
PM	particulate matter
PM ₁₀	particulate matter less than 10 microns in diameter
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
QA/QC	quality assurance/quality control
RCW	Revised Code of Washington
RICE	Reciprocation Internal Combustion Engine
RO	Regulatory Order (issued by the NWCAA)
SCF	Standard cubic feet
SCFM	Standard cubic feet per minute
SCR	selective catalytic reduction
SEPA	State Environmental Policy Act

SMR	steam methane reformer
SOB	Statement of Basis (AOP)
SOP	Standard Operating Procedure
SRU	Sulfur Recovery Unit
SIP	State Implementation Plan
SO ₂	sulfur dioxide
TAB	Total Annual Benzene
TGTU	Tail Gas Treating Unit
TPY (tpy)	Tons per Year
TVP	True Vapor Pressure
ULNB	Ultra-Low NO _x Burner (designed for ≤ 0.04 lb/MMBtu)
VE	Visual Emissions
VPS	Vacuum Pipe Still (Crude Unit)
VOC	volatile organic compounds
VOL	volatile organic liquid
WAC	Washington Administration Code
WDOE	Washington State Department of Ecology (Ecology)
WESP	wet electrostatic precipitator
WWSG	Waste Water Stripper Gas

5 AIR OPERATING PERMIT MODIFICATIONS

5.1 April 2014 modification (015R1M1)

In accordance with WAC 173-401-730, the NWCAA has a legal requirement to incorporate new and revised OACs, regulatory orders, and regulations into the AOP. The April 2014 modification meets this requirement. The following changes were made to the AOP:

1. Best Available Retrofit Technology (BART) Order 7836, Revision 1

The Washington Department of Ecology issued revision 1 to BART Order 7836 on August 16, 2013. This revision removed references to Boiler 6 and Boiler 7 from the BART Order as these units were not BART eligible. BART Order 7836 was replaced by BART Order 7836 Revision 1 in the AOP.

2. Boiler MACT – 40 CFR 63 Subpart DDDDD

The Boiler MACT wasn't final as of the date AOP 015R1 was issued. The regulation has since been finalized. BP operates refinery gas fueled units which are affected sources under the rule. The applicable Boiler MACT requirements for affected units were added to the AOP.

3. OAC 1001 Revision C (OAC 1001c)

BP requested a modification to OAC 1001, which approved the operation of the #6 and #7 utility boilers. The changes requested by BP were approved under OAC 1001c. OAC 1001c superseded OAC 1001b, which was previously listed in AOP 015R1. OAC 1001b was removed from the AOP, and OAC 1001c was added in its place.

4. OAC 1064 Revision A (OAC 1064a)

BP requested a modification to OAC 1064, which approved a new hydrogen plant and new diesel hydro-desulfurization unit as part of BP's Clean Fuels project. The changes requested by BP were approved under OAC 1064a. OAC 1064a superseded OAC 1064, which was previously listed in AOP 015R1. OAC 1064 was removed from the AOP, and OAC 1064a was added in its place.

5. OAC 1142

OAC 1142 approved the construction of the new crude oil railcar unloading terminal. OAC 1142 was issued on January 22, 2013, which was after the issuance date of AOP 015R1. The OAC has been added to Emission Unit 15, Shipping, Pumping, and Receiving.

6. Other Changes

Corrected typo to the description of the regulatory requirements in several sections.

Changed regulatory citation in AOP term 5.17.8 dealing with 40 CFR 61 Subpart FF. There are compliance options in Subpart FF. BP has chosen to comply with the 10 ppm flow-weighted annual average limit, measured at the biodegradation unit. A change was made to the AOP to list this option instead of the option to comply with the benzene limit in the NPDES permit.

Clarified applicability of opacity monitoring to calciners, incinerators, and tail gas units. Clarified actions BP must take if Ecology Method 9A monitoring shows visible emissions are below the applicable limit.

Approved the use of test method CTM-13B for OAC required testing at the calciners.

Added information to the statement of basis about when the NWCAA may approve testing under 90% steam load conditions, vs. testing under 90% of max heat input.